South Coast Air Quality Management District
Planning, Rule Development & Area Sources

Draft Staff Report
SOx RECLAIM

Part 1
BARCT Assessment & RTC Reductions Analysis

October 1, 2010

Deputy Executive Officer
Elaine Chang, DrPH

Assistant Deputy Executive Officer
Laki Tisopulos, Ph.D., P.E.

Planning and Rules Manager
Joe Cassmassi

Author
Minh Pham, M.S., P.E., Air Quality Specialist

Contributor
Kevin Orellana, Air Quality Specialist

Reviewers
Gary Quinn, P.E., Program Supervisor
Joe Cassmassi, Planning & Rules Manager
Laki Tisopulos. Ph.D., P.E., Assistant DEO
William Wong, Principal Deputy District Counsel

Acknowledgements

The author would like to thank the following AQMD's staff members for providing information and participating in this project:

Planning, Rule Development & Area Sources Division
Susan Yan, Kathy Hsiao, Ali Ghasemi, Tuyet-Le Pham, Barbara Radlein, Steve Smith, Shah Dabirian, Sue Lieu, Tom Chico, Jillian Baker

Engineering & Compliance Division
Danny Luong, Mitch Haimov, Susan Tsai, Fortune Chen, Kyu Kyu Leung, Christian Hynes
Tran Vo, Jay Chen & Refinery Team, Brian Yeh & his team

Information Management Division
George Haddad, Rezvan Ramezani

Source Testing Division
Mike Garibay & his team, Ramiro Gonzalez, Steve Marinoff

Technology Advancement Office
Marty Kay

TABLE OF CONTENTS

Executive Summary

RECLAIM Program & Best Available Retrofit Control Technology

On October 15, 1993, the District's Governing Board adopted Regulation XX - Regional Clean Air Incentives Market (RECLAIM) and established a declining cap and trade mechanism to reduce NOx and SOx emissions from the largest stationary sources in the South Coast Air Basin (Basin). Regulation XX is comprised of 11 rules that specify the rules applicability, NOx and SOx facility allocations, general requirements, as well as monitoring, reporting, and recordkeeping requirements for NOx and SOx sources located at RECLAIM facilities. The RECLAIM program started with 41 SOx facilities and 392 NOx facilities. By the end of 2005 compliance year, the program included 33 SOx facilities and 304 NOx facilities. By the end of 2008, the SOx facilities reduced to 32 facilities.

Under the SOx RECLAIM program, the RECLAIM facilities are issued SOx annual allocations (also known as facility caps), which decline annually from 1993 until 2003 and remain constant after 2003. The annual allocations issued to the RECLAIM facilities reflect the levels of Best Available Retrofit Control Technology (BARCT) envisioned to be in place at the RECLAIM facilities, and were the results of a ~~Best Available Retrofit Control Technology (~~BARCT~~)~~ analysis in 15 years, conducted in 1993. Since 1993, the District conducted ~~a~~one BARCT reassessment for NOx in 2005, and has not yet conducted a BARCT reassessment for SOx. Under the RECLAIM program, the facilities have the flexibility to install air pollution control equipment, change method of operations, or purchase RECLAIM Trading Credits (RTCs) to meet the BARCT levels.

AQMD staff is proposing amendments to Regulation XX – RECLAIM to achieve additional SOx reductions pursuant to the 2007 AQMP Control Measure CMB-02. The proposed amendments address requirements for ~~Best Available Retrofit Control Technology (~~BARCT~~)~~ in accordance with California Health and Safety (H&S) Code §40440, which is applicable to market-based incentive programs, as well as equivalency to command-and-control regulations, as required under H&S Code § 39616(c)(1). Reductions in SOx will help the Basin attain the federal annual average PM2.5 standard by 2015, and the federal 24-hour average standard by 2020. Other proposed rule amendments include clarifications and changes to the protocols.

PM2.5 Implementation Rule

In March 2007, the U.S. Environmental Protection Agency (EPA) issued a final rule, known as the *Clean Air Fine Particle Implementation Rule*, which requires non-attainment areas such as the South Coast Air Basin to meet the fine particulate ($PM_{2.5}$) standards by 2010. The *Clean Air Fine Particle Implementation Rule* requires the District to achieve the fine particulate standards as expeditiously as possible, and allows the District a one-time extension up to five years but no later than 2015. The rule requires the District to evaluate and employ all control measures to reduce the direct $PM_{2.5}$ emissions, as well as the emissions from $PM_{2.5}$ precursors, specifically sulfur dioxide (SO_2), and the most potent $PM_{2.5}$ precursors.

2007 Control Measure CMB-02 - Further SOx Reduction for RECLAIM (SOx)

To establish the basis for future compliance with the final U.S. EPA rule, staff has developed the 2007 Air Quality Management Plan (AQMP) Control Measure CMB-02 – Further SOx Reduction for RECLAIM (SOx) adopted by the Governing Board in July 2007. This control measure proposed to further reduce SOx allocations by approximately 3 tons per day in 2011-2014 to help the basin achieve the PM2.5 standards by 2014 and also stated ~~indicated~~ that ~~that~~ staff may need to incorporate the concept of facility modernization as described under Control Measure MCS-01 - Facility Modernization to achieve additional reductions beyond 2014 to meet the 2020 24-hour standard.

RTC Holdings, 2005 Emissions Distribution & BARCT Area of Focus

In 1993, the District issued a total of 12 tons per day of SOx allocations ~~caps~~ for the 2003 compliance year and beyond for the facilities in SOx RECLAIM. This is also the 2002 baseline for RECLAIM facilities used in the 2007 Air Quality Management Plan. It should be noted that the SOx RECLAIM emissions and RTC market are not distributed uniformly: In 2005, the SOx RECLAIM facilities ~~reported~~emitted a total of 10.04 tons per day emissions.; ~~However,~~ more than 92% of the emissions was generated by the top 11 facilities; and in these 11 facilities, the top 7 source categories listed below were responsible for 80% of the facility emissions.

- Fluid catalytic cracking units;
- Sulfur recovery and tail gas treatment units;
- Boilers and heaters using refinery gas;
- Sulfuric acid manufacturing plants;
- Container glass melting furnace;
- Coke calciner;
- Cement kilns and a coal steam boiler at a cement manufacturing facility.

These top emitters emitted approximately 7.53 tons per day in 2005 and are the focus for BARCT evaluations in this proposed rule amendment. The remaining facilities either do not have any equipment subject to proposed new BARCT, or their facility emissions are too low to make BARCT cost-effective. Figure EX-1 presents the 2005 emissions distribution, and Figure EX-2 presents a comparison for RTC Holdings and emissions between the top 11 facilities and the remaining 21 active facilities in SOx RECLAIM universe.

FIGURE EX-1
2005 Emissions Distribution

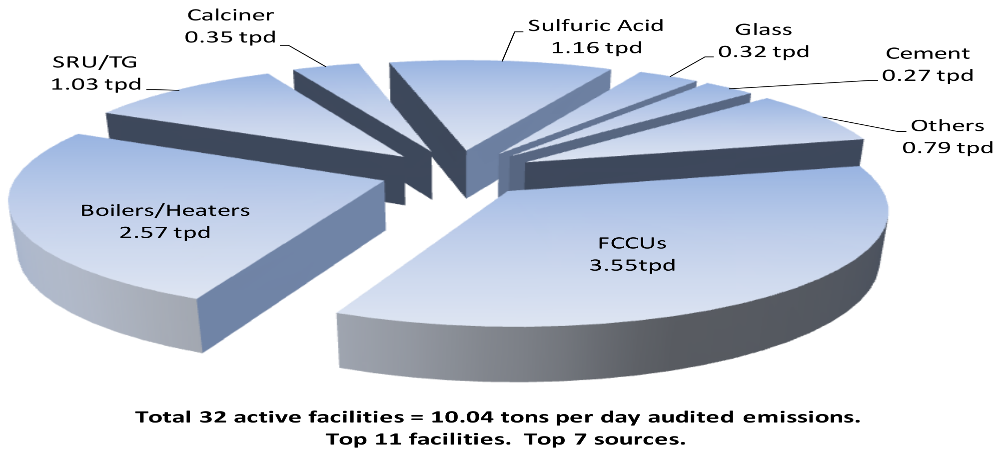
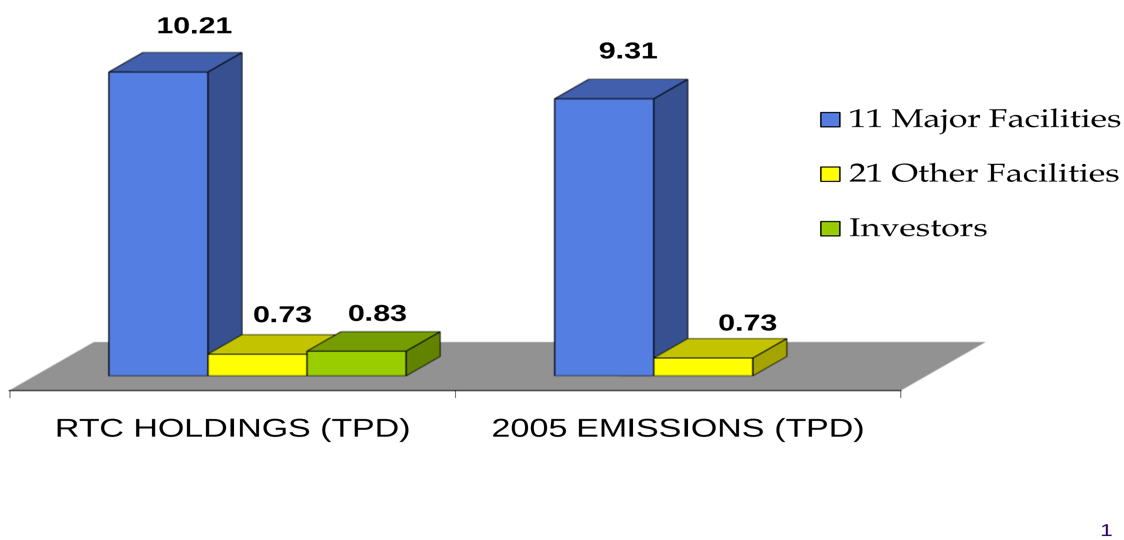


FIGURE EX-2
Distributions of RTC Holdings versus 2005 Emissions



Public Process

The public process of the PAR XX is summarized in Table EX-1. In 2008, staff formed the RECLAIM Working Group that included members representing SOx RECLAIM facilities, the Western States Petroleum Association (WSPA), the environmental community, as well as CARB and U.S. EPA to discuss and brainstorm the proposed amended SOx RECLAIM. The first meeting was conducted on February 7, 2008.

On April 3, 2008, staff released the first Preliminary Draft Staff Report, and conducted two Working Group meetings on April 3 and April 30, 2008 to discuss staff's initial proposal including allocations, emissions inventory and distribution, and potential BARCT for seven (7) major emitting categories of stationary source equipment located at the eleven (11) major SOx RECLAIM facilities.

In May 2008, staff, WSPA and the refineries worked in collaboration to develop a Request for Proposal (RFP) to solicit expert consultants to conduct independent studies on feasibility and cost effectiveness. Additional working group meetings were held on May 15, May 28, and July 2 to discuss the Request for Proposal. On July 11, 2008, the Governing Board approved the release of the RFP and staff conducted a Bidder's Conference immediately after. A public notice advertising the RFP and inviting bids was published in accordance with AQMD's Procurement Policy and Procedure. The District's procurement office received and accepted a total of six (6) proposals.

Staff formed an evaluation panel in August 2008 to evaluate the potential contractors. The four member evaluation panel consisted of one AQMD Assistant Deputy Executive Officer from Planning, Rule Development, and Area Sources Division; one AQMD Program Supervisor of the Best Available Control Technology team; one AQMD Program Supervisor of the Refinery Team; and one representative from WSPA. Staff invited one representative from the environmental group and two representatives from the U.S. ~~EPA,~~EPA; however, they could not participate in this evaluation process due to schedule conflicts.

The panel was in agreement that the contractors possessed good qualifications, presented good approaches and had workable schedules. After serious consideration, the panel recommended the Governing Board ~~to~~ award the contracts to:

- ETS, Inc. in the amount not to exceed $289,360 to conduct analyses for refinery Fluid Catalytic Cracking Units (FCCUs), boilers/heaters, and sulfur recovery units and tail gas treatment units (SRU/TGTUs); and

- NEXIDEA Inc. in the amount not to exceed $45,500 to conduct analyses for sulfuric acid manufacturing facility and a coke calciner facility.

The panel recommendation was approved by the Governing Board in a public meeting on September 5, 2008. The two consulting firms started the projects immediately after receiving the awards. First, the consultants and staff scheduled and conducted site visits at BP, Chevron, ConocoPhillips, Tesoro, Valero, ExxonMobil, California Portland Cement, Owens Brockway, and Rhodia in September and October 2008. During these site visits, the consultants gathered all necessary technical information on equipment and operating conditions, discussed ~~with the facilities on~~ operational characteristics of the equipment with the facilities, observed the physical layout of the equipment, as well as listened to any concerns or foreseen constraints provided by the refinery technical experts related to future prospective add-on control devices.

After the site visits, the consultants conducted their own independent research, contacted the control manufacturers and vendors, gathered cost information, and performed their own independent engineering analyse~~i~~s on commercially available control technologies and cost effectiveness. In October 2008, the consultants developed the draft reports which were distributed to the affected facilities and AQMD staff for comments. After addressing all comments received from the facilities, as well as AQMD staff, the consultants finalized their analyses and reports for coke calciner, cement kilns, coal fired boiler, glass furnaces, and sulfuric acid plants on December 16, 2008 as planned in the contracts.

Because of the complexity associated with the refinery systems, the analyses related to FCCUs, SRU/tail gas, and fuel gas treatment could not be completed in December 2008. The contractors and staff scheduled another round of ~~second~~ extensive site visits at all six refineries in January and February 2009. The consultants' draft analyses were provided to the refineries a total of four times (October 2008, January, February and March 2009) for comments. The primary consultant, ETS, Inc., and the subcontractor, AEC Engineering, addressed substantial amount of comments received from all six refineries, revised their reports appropriately, and finalized their assessment for the refineries in April 2009. The non-confidential reports from NEXIDEA, ETS and AEC Engineering are available for public information.

In 2009, staff reconvened the Working Group meetings. A Public Workshop was conducted on June 23, 2009, and in this workshop, staff released 1) the Draft Staff Report to discuss BARCT, cost effectiveness, RTC reduction methodology, and timing of the proposed rule implementation; 2) Notice of Preparation of the Draft Environmental Assessment; and 3) the Draft PAR XX. In addition, staff conducted numerous meetings with WSPA and WSPA members, and other affected facilities as requested. Two ~~most recent~~ Working Group meetings were held on August 27 and December 15, 2009.

At the January 8, 2010 Governing Board Meeting, staff conducted an Informational Hearing to inform the Governing Board and the public about the development of PAR XX, the main issues associated with the proposed amended rule, and proposed a Work Plan for 2010 which was developed in collaboration with WSPA and provided a roadmap towards resolving pending issues. To address concerns by WSPA relative to the feasibility and cost analyses conducted by ETS/AEC and NEXIDEA in 2008-2009, the Governing Board approved in January 2010 the hiring of a second consultant to provide an independent review of the analyses previously conducted. To fulfill that commitment, staff hired Norton Engineering Inc. (NEC) to review ETS, Inc. and NEXIDEA's feasibility and costs analyses. NEC was the next highest ranked consultants from the six initially reviewed, and the highest ranked by WSPA. NEC and staff visited the refineries in March/April, and NEC completed its review and issued a final report on June 15. Between April to June, staff met with WSPA and the refineries numerous times to discuss RTC shave methodologies, costs, and estimate impacts to the refineries.

On August 18, 2010, staff released its Draft CEQA document concurrently with the second Refinery Committee Meeting addressing SOx RECLAIM. Staff also conducted a Public Working Group Meeting and a Public Consultation Meeting on September 8, 2010. Staff's revised estimates for BARCT reductions at this time were 5.4 tpd emission reductions from 2005 baseline, 6.1 tpd RTC reductions from 2012 – 2019 amounting to a 55% RTC shave. The estimated total costs are $630 - $745 millions, and cost effectiveness of about $16 K - $19 K per ton SOx reduced.

In staff's current proposal, several significant changes have been made as follows: 1) exclusion of emission reductions of 0.85 tpd estimated from boilers/heaters since the proposed BARCT limit was unchanged from the previous BARCT level of 40 ppmv; 2) use of audited emissions in the analysis for RTC shave, and 3) extension of the compliance period to 2019 instead of 2017 as previously proposed, and 4) accounting for growth in emissions as was done in the 2005 BARCT reassessment under NOx RECLAIM.

The proposed amendments to SOx RECLAIM have been scheduled to be presented to the Governing Board for consideration at the November 5, 2010 Governing Board Meeting.

TABLE EX-1
Summary of the rule development process for Proposed Amended Regulation XX

Calendar Year 2008	
January 02, 2008	RECLAIM Working Group was formed
February 07, 2008	Public Consultation Meeting was conducted
April 03, 2008 April 30, 2008	Preliminary Draft Staff Report was released. Two Working Group Meetings were conducted.
May 1, May 15, May 28, June 20, July 02, 2008	Request for Proposal to seek expert consultants was drafted and discussed with the RECLAIM Working Groups on three Working Group Meetings from May to July. A Stationary Committee Meeting was also conducted on June 20.
July 11, 2008 July 16, 2008	RFP was presented to the Governing Board, and received Governing Board's approval to release on July 11. A Bidder Conference was conducted on July 16
August 1, 2008 August 30, 2008	Staff formed a task force to evaluate the six proposals received & make recommendation to the Governing Board
September 5, 2008	Staff presented the recommendation of consultants to the Governing Board and received an approval to hire ETS, Inc. and NEXIDEA
September 15, 2008 October 15, 2008	The consultants visited the facilities and conducted their feasibility and cost analyses, and the draft analyses were released to the facilities for comments.
December 16, 2008	NEXIDEA finalized the analyses for coke calciner and sulfuric acid plants. ETS Inc. finalized the analyses for glass and cement facilities.
Calendar Year 2009	
January – April 20, 2009	ETS Inc., their subcontractors, and staff conducted a second visit to all refineries. ETS, Inc. released their draft analyses three additional times to the refineries for comments and finalized their analyses on April 20, 2009.

June 23, 2009 (Public Workshop and CEQA Scoping Meeting)	Staff conducted a Public Workshop and CEQA Scoping Meeting. At this stage, staff proposed about 7 tpd RTC reduction from 2012-2017 with a total costs (present worth value for 25 years) estimated to be \$883 - \$944 million dollars and a weighted average cost effectiveness of about \$16 K per ton SOx reduced. Staff released the draft staff report, Notice of Preparation for Environmental Assessment, and draft rule.
June 19, 2009 November 20, 2009	Two Stationary Committee Meetings were conducted in 2009. In addition, from March – December, staff conducted several meetings with WSPA and the refineries to discuss issues related to costs, baseline and RTC shave methodologies.
December 11, 2009 December 15, 2009	The Governing Board established a Refinery Committee Group and conducted the first Refinery Committee Meeting on December 11, 2010, and a Working Group Meeting on December 15. At this stage, staff's estimates were 6.2 tpd emission reductions from 2005 baseline, 7.5 tpd RTC reduction, 64% - 67.5% RTC shave, total estimated costs of \$745 million, and cost effectiveness of about \$13 K per ton SOx reduced.
Calendar Year 2010	
January 08, 2010 (Informational Hearing)	Staff conducted an "Informal Hearing" to inform the Governing Board and the public about the development of PAR XX, the main issues associated with PAR XX, and a proposed Work Plan for 2010.
March 10, 2010 – June 15, 2010	As called for under the Work Plan and approved by the Governing Board, staff hired a Norton Engineering Inc. (NEC) to review ETS, Inc. and NEXIDEA's feasibility and costs analyses. NEC and staff visited the refineries in March/April, and NEC completed its review and issued a final report on June 15. In April – June, staff also met with WSPA and the refineries numerous times to discuss RTC shave methodologies and costs. In addition, staff met with WSPA and the refineries numerous times from March – August to discuss SOx shave methodology, initial allocations, RTC reduction estimates, costs and cost-effectiveness analyses. In addition, staff contacted the California Department of Water Resources and other water purveyors to discuss about the water impacts of the proposal, current and potential future regulations related to water usage in California.
August 18, 2010	Draft CEQA document was released and staff conducted a second Refinery Committee Meeting. Staff's revised estimates were 5.4 tpd emission reductions from 2005 baseline, 6.1 tpd RTC reduction from 2012 - 2019, 55% RTC shave, total estimated costs of \$630 - 745 million, and cost effectiveness of about \$16 K - \$19 K per ton SOx reduced. Staff excluded the emission reductions of 0.85 tpd estimated from boilers/heaters, used audited emissions in the analysis for RTC shave, extended the compliance period to 2019 and accounted for growth.
September 8, 22	Staff reconvened the Working Group Meeting & conducted a

and 24, 2010	Public Consultation Meeting on September 8, a Refinery Committee Meeting on September 22, and a Stationary Source Committee Meeting on September 24, 2010.
November 5, 2010	A Governing Board Hearing is planned for November 5, 2010.

Current Staff Proposal for BARCT and SOx RTC Reductions

To estimate SOx RTC reductions, staff used the RTC reduction methodology first developed in the 2005 NOx RECLAIM rule amendment. In this methodology, the base year inventory (i.e., 1997) was selected. Associated growth factors were used to project the 1997 audited emissions to year ~~2014~~2019. BARCT adjustment was then applied to the projected ~~2014~~2019 inventory to calculate the remaining emissions at BARCT levels. Staff then applied a 10% adjustment (increase) to the remaining emissions to account for inaccessible RTCs due to imperfect market conditions and RTCs held by facilities to ensure compliance with annual audits. ~~Using this methodology, staff estimated a total SOx RTC reductions of 7.5 tons per day, approximately 64% reductions of RTC's holdings of 11.76 tons per day in year 2014 assuming an implementation across-the-board based on equal percent reductions to all RTC holdings.~~
The proposed project results in 5.4 tons per day emission reductions from the 2005 baseline. This is equivalent to 6.1 tons per day RTC reduction, approximately 55% reductions of RTC's holdings of 11.09 tons per day by 2019.[1]

In staff's current proposal shown in Table EX-2, staff made the following changes:

- Staff removed emission reductions estimated for boilers/heaters. Since the proposed BARCT limit is retained at 40 ppmv for boilers/heaters, any reductions estimated for boilers/heaters from the 2005 baseline are considered as "opportunity reductions" that the facilities may select to implement, but not as reductions due to new BARCT.

- Staff used 1997 audited emissions instead of reported emissions to estimate RTC shave,

- Staff provided additional 2 years for implementing the RTC reductions as requested by several RECLAIM facilities, and extended the implementation period to 2019 and incorporated growth factor adjustments to reflect the extension period.

TABLE EX-2
Staff's Proposal

	2014	**2017**	**2019**
Original Proposal in January 2010	RTC reduction = 4.5 tpd RTC Shave = 41%	RTC reduction = 7.5 tpd RTC Shave = 67.5%	
Current Proposal	RTC reduction = 4.5 tpd RTC Shave = 41%		RTC reduction = 6.1 tpd RTC Shave = 55%

Note: Percentage shave is calculated using RTC holdings of 11.09 tons per day for major emitters and investors. Current unused RTCs based on 2008 emissions = 11.77-9.22=2.55 tpd (22% of 11.09 tons per day)

[1] Based on RTC records as of August 29, 2009

Table EX-3~~The attached table~~ shows the new proposed BARCT levels, Tier I current BARCT levels, the percent reduction from Tier I and the estimated cost effectiveness for each of the seven (7) categories of sources located at the eleven (11) major facilities:

TABLE EX-~~1~~3
Proposed New BARCT Levels

	Tier I (1993 Projected BARCT for Year 2000)	**New BARCT**	**Emission Reductions from 2005**	**% Reduction from Tier I**	**Cost Effectiveness (note 1)**
FCCUs	13.7 lbs/Mbarrels	5 ppmv ~~13.7~~3.25 lbs/Mbarrels	2.88 tons/day	~~80%~~76%	$20K - $21K per ton
SRU/TGs	Reported Value Avg 9.03 lbs/hour	5 ppmv 5.28 lbs/hour (note 2)	0.73 tons/day	42%	~~$26~~31K - $45K per ton
Boilers & Heaters	6.76 lbs/mmscft	40ppmv 6.76 lbs/mmscft	0.00 tons/day	0%	Not Applicable
Sulfuric Acid	Reported Value Avg 5.08 lbs/hour	~~5~~10 ppmv 0.14 lbs/hour	1.03 tons/day	97%	$2K - $3K per ton
Coke Calciner	Reported Value Avg 2.47 lbs/ton coke	~~5~~10 ppmv 0.11 lbs/ton coke	0.28 tons/day	~~97%~~96%	$10K - $23K per ton
Container Glass	Reported Value Avg 2.51 lbs/ton	5 ppmv ~~5.28 lbs/hour~~ 0.03 lbs/ton	0.19 tons/day	~~98%~~99%	$5K per ton
Cement Kilns	Reported Value Avg 0.05 lbs/ton	5 ppmv 0.04 lbs/ton	0.25 tons/day	20%	$19K - $27K per ton
Coal Fired Boilers	Reported Value	95% reduction	0 tons/day **	95%	$4 K per ton

Note: 1) The first figure of the range reflects the cost effectiveness estimated based on ETS/AEC/NEXIDEA analyses, and the second figure reflects the cost effectiveness estimated based on input provided by Norton Engineering. ** Equipment not in operation in 2005. 2) 5 ppmv is for combusted tail gas.

The net facility investment ~~of staff's proposal~~ for BARCT was estimated to be $630 million - 745 million dollars. The weighted average cost effectiveness was about ~~$13K~~$16 K - $19K per ton SOx reduced, with a range from $2K to ~~$47K~~$50K per ton SOx reduced. Figure EX-3 presents the emission reductions estimated from the 2005 baseline. Figure EX-4 presents the estimated costs (the present worth values for 25 years) based on the first set of consultants' (ETS/AEC and NEXIDEA) estimates. The second consultants estimated the costs of about $750 million dollars for the proposed projects.

The ~~7.5~~revised 6.1 tpd RTC reductions would be implemented ~~in six (6)~~ over eight (8) ~~phases~~years:

- 1.5 tons per day of reductions in compliance year 2012
- 1.5 tons per day of reductions in compliance year 2013
- 1.5 tons per day of reductions in compliance year 2014
- ~~1~~ 0.32 tons per day of reductions in compliance year 2015
- ~~1~~0.32 tons per day of reductions in compliance year 2016
- ~~1~~0.32 tons per day of reductions in compliance year 2017
- 0.32 tons per day of reductions in compliance year 2018
- 0.32 tons per day of reductions in compliance year 2019

Staff proposed to submit the first ~~3~~4.5 tons per day RTC reductions to EPA to satisfy the SIP commitment and help the Basin meets the standard in 2015. The remaining reductions would be submitted at a later phase.

FIGURE EX-3
Emission Reduction (Tons per Day) from 2005 Baseline

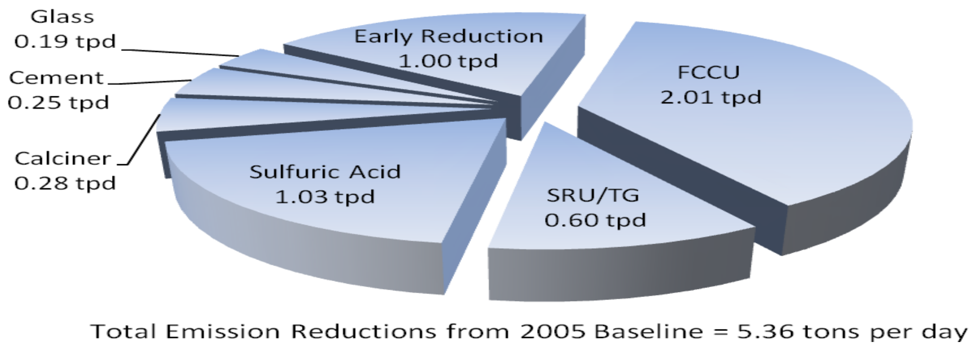
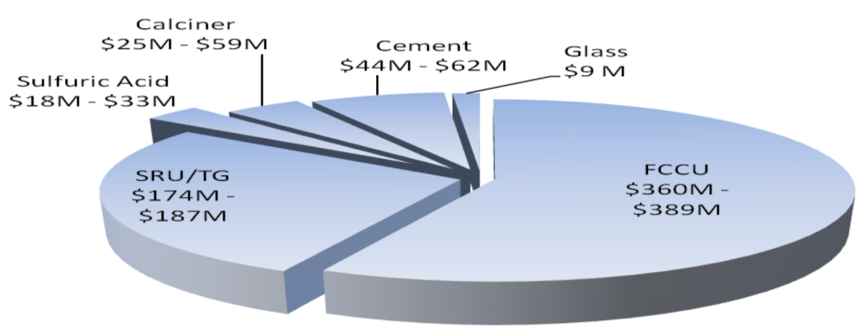


FIGURE EX-4
Present Worth Values for 25 years (Million Dollars) Based on ETS/AEC, NEXIDEA's and Norton Engineering Estimates (Excluding Cost-Ineffective Controls of >$50 K per Ton)

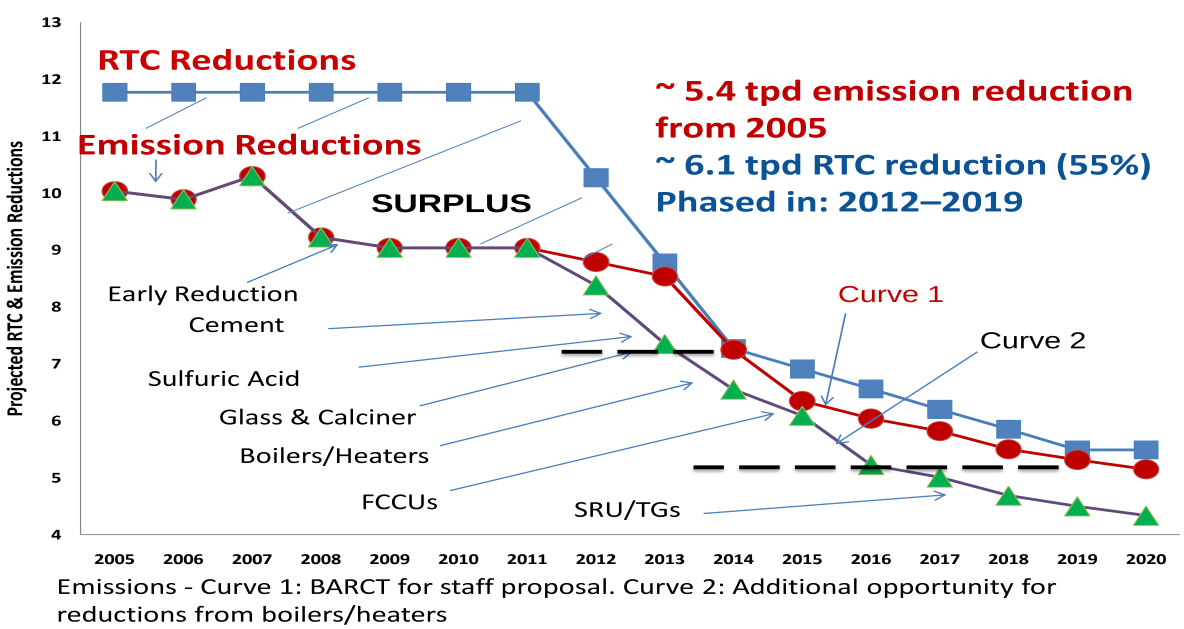


SOx RECLAIM project = $630 M - $738 M, 5.4 tpd emission reductions, cost effectiveness = $16 K - $19K per ton. Refinery sector = $561 M - $638 M, 3.9 tpd emission reductions.

Figure EX-5 shows the RTC reductions as proposed by staff. Figure EX-5 also shows the reported emissions from 2005 – 2008 and the amount of unused RTCs available in the market. In Figure EX-5, Curve 1 and Curve 2 represent two hypothetical but realistic emission reduction scenarios that use cost effectiveness as the key variable to phase-in source category compliance in future years. In Curve 1, it is assumed that BARCT would be implemented for cement, sulfuric acid, glass, and calciner by year 2014, and BARCT for FCCUs and SRU/TGs would be implemented after 2014. In Curve 2, it is assumed that RECLAIM facilities would implement voluntarily the cost-effective control measures identified by the consultants for boilers/heaters to meet the Tier 1 BARCT. The first dashed line in Figure EX-5 shows that because there is ample amount of RTCs currently available in the market comprised of unused RTCs (2.55 tpd) in the market, early reductions achieved at two refineries (1 tpd), and reductions from currently not operative cement kilns (0.25 tpd), the RECLAIM facilities will be in compliance with the proposed shave in 2014 without significant expenditures on BARCT for major equipment such as FCCUs and SRU/TGs. Implementing BARCT for FCCUs and SRU/TGs will likely take place after 2014 to meet the target of 2019. However, careful evaluation of the second dashed line in Figure EX-5 intersects with Curve 2 suggests that in perfectly operating market, many of the estimated expenditures for FCCU's and SRU/TG's controls may not be necessary after all.

The draft CEQA ~~, socioeconomic and market~~ analys~~es~~is for this proposed rule amendment ~~are currently in progress~~was released on August 18, 2010. The draft socioeconomic analysis was released with this revised draft staff report. The draft rule language for the proposed Rule 2002 is attached with this revised draft staff report. Rule development is ongoing and staff is committed to working with all stakeholders throughout the process.

FIGURE EX-5 [2]
Staff's Proposal and Potential Compliance Scenarios



[2] The assumptions used in Figure EX-5 are as follows: 1) early implementation occurred in 2008-2009; 2) In late 2009, CPCC announced the shutdown of the cement kilns, which may or may not be permanent, and to the extent that when the economy improves, they plan to bring the cement kiln on-line. An assumption was made that either CPCC would sell their unused RTCs in 2013 or installed control equipment to achieve emission reductions; 3) Controls for sulfuric acid will be implemented in 2013, for glass and calciner in 2014, for FCCUs and SRUs in 2015 – 2020; and 4) any opportunity reduction from boilers/heaters will be implemented in 2012-2015.

Key Issues

There are four (4) key issues raised by the stakeholders: 1) BARCT determination, 2) water and wastewater, 3) market viability, ~~and~~ 4) shaving methodology for facilities that are not subject to new BARCT, and for facilities that are subject to new BARCT. Staff's responses to these key issues are summarized below:

1) BARCT Determination

Stakeholders commented that staff should pursue only 3 tons per day reduction as stated in the 2007 AQMP to meet the SIP commitment. The current trend of PM2.5 is declining and does not warrant a SOx shave that is estimated to cost industry over one billion dollars. In addition, the costs and cost effectiveness were under-estimated and environmental impacts (e.g. water, energy) were not appropriately analyzed.

Staff's Response: For a market based incentive program, staff is required by the H&S codes to conduct periodic BARCT reassessment and demonstrate equivalency with command-and-control rules which would otherwise be developed as a result of BARCT reassessment:

> *"…achieve an equivalent or greater level of emission reductions at an equivalent or lower cost as would have been achieved under a command-and-control rule"*

The percent RTC reduction (~~64%~~55%) that staff estimated for the SOx RECLAIM universe ~~as a whole~~ is still much less stringent than the percent reduction (90% - 98%) that could be imposed to specific categories of sources such as FCCUs, SRU/TGs, sulfuric acid plant, cement plant, coal fired boiler, and glass melting furnaces under the command-and-control approach.

Furthermore, it should be noted that SOx is a significant building block of PM2.5. Chemical speciation of PM2.5 samples indicated that in the South Coast Air Basin 25% of the ambient PM2.5 is attributed to contribution from sulfates. Furthermore, SOx reductions are highly effective in reducing ambient PM2.5 levels as compared to other primary and secondary contributors to PM2.5 formation (1 tons SOx = 1.5 tons PM2.5 = 15 tons NOx). Therefore, the reductions of SOx are essential for the Basin to meet the federal annual standard of PM2.5 by 2015 and the federal 24-hour average standard of PM2.5 by 2020. As indicated in the 2007 AQMP, the control strategies included in the Plan to meet the annual PM2.5 standard when fully implemented will fall short of meeting the 24-hour standard by approximately 30%. Therefore, additional reductions above and beyond the control strategies committed in the 2007 AQMP for meeting the 2015 annual PM2.5 standard are necessary to meet the 24-hour PM2.5 standard in 2020. For further information, please refer to Chapter 5 of the 2007 AQMP.

In addition, it is worth mentioning that the U.S. EPA is proposing to set a new, more stringent, one-hour standard for SO2 between 50 – 100 parts per billion (ppb) and revoke the current 24-hour of 140 ppb and the current annual standard of 30 ppb to further protect public health. The U.S. EPA and the state are also proposing to tighten the annual average PM2.5 standard.

Regarding the costs and cost effectiveness analyses, after verifying the consultants' analyses, staff formulated its proposal based largely on consultants' recommendations. In response to comments from industry related to costs and in an effort to optimize the effectiveness of its proposal, staff removed the least cost effective control strategies (exceeding $50,000 per ton SOx reduced) from staff proposal. While these refinements to the staff proposal have reduced anticipated reductions by 5% (0.33 tons per day), they improved the overall cost effectiveness to ~~$13,000~~$16 K- $19K per ton SOx reduced and reduced the total compliance costs by 25%. To further reduce the cost impacts, staff proposes to spread the potential emission reductions over ~~6~~8 years starting from 2012. Staff also proposes to submit only 3 tons per day reductions to satisfy the SIP commitment in Phase 1 (i.e. 3 tpd reductions by 2014). The remaining reductions will be submitted later.

2) Water & Wastewater Impacts

Stakeholders commented that the water and wastewater impacts of the project ~~will~~would be significant.

Staff's Response: Industry argues that staff proposal will result in significant increases on water demand and wastewater impacts due to the water-intensive operation of wet gas scrubbers. To the extent that wet gas scrubbers are used to comply with the proposed SOx control requirements of the proposed project, staff acknowledges that the total water demand will increase, (by approximately 1 million gallons per day or 3 acre feet per day), but increased water demand over current water usage at affected facilities is well below the SCAQMD's significance threshold of 5 million gallons per day of total increased water demand (i.e. potable water, recycled water, and groundwater). The information that staff received to date from the water purveyors and collected from their 2005 Urban Water Management Plans is that there are adequate supplies to meet the total water demand because the water demand can be largely offset by recycled water and groundwater sources. Availability of water supplies to meet increased water demand is another water demand significance threshold criterion. Even though the potential increase in total water demand is below the SCAQMD's significance threshold of 5 million gallons per day, and because California is in a state of emergency for drought, staff has identified another criterion for what would be considered a substantial use of when determining whether a project, could be considered a "water demand" project as defined by CEQA. Using the more stringent criterion of what constitutes a potable water demand project, the potable water demand of the proposed project would ~~not qualify as a "water demand" project since quantified potable water demand from the proposed project does not~~ exceed the more stringent criterion if recycled water was not utilized. Currently, recycled water is used at the three refineries in the basin and the water purveyors indicated that, as part of their Urban Water Management Plans, they are in the process of expanding their pipeline service to serve the remaining refineries. Therefore, in the spirit of utilizing abundance of caution, it was determined to classify the water impacts of the proposed project as significant and the impact of the proposed project can be mitigated by the use of recycled water, if available.

Relative to the wastewater impact, staff's analysis based on the Survey[3] conducted among the affected facilities indicates that the overall wastewater increase will be less than 2% and that the facilities have adequate wastewater treatment capacity to treat the increase in wastewater generated. An increase of 25 percent would trigger a permit revision and would be considered a significant adverse wastewater impact. Since all of the affected facilities have been shown to

[3] Staff developed a Survey Questionnaire and sent to the impacted facilities in July 2009 to collect current information related to water usage and wastewater generated at the facilities. The results of the responses from the facilities are summarized in Chapter 11 of this Staff Report.

have a potential wastewater increase less than 25 percent, no modifications to any existing wastewater discharge permits are anticipated as a result of the proposed project. Nevertheless, staff will continue working with water purveyors and the impacted facilities to further refine the water demand analysis and analyze other impacts and alternatives.

3) Market Viability

Stakeholders commented that there were not enough trading partners, the SOx market was very competitive and reserved, and there was an uneven distribution of RTC holdings.

Staff's Response: For a market based incentive program, staff is required by the H&S codes to conduct periodic BARCT reassessment and demonstrate equivalency with command-and-control rules which would otherwise be developed as a result of BARCT reassessment. To ease the issues identified by the stakeholders, staff is proposing to return a portion of the reductions to the facilities as a compliance margin (10%). This approach was also utilized as part of the 2005 NOx RECLAIM amendments. In addition, staff is proposing to establish a set-aside, non-tradable reserve that could be tapped in when RTC value in the open market reach a certain level. Staff is also proposing to submit ~~only three (3)~~4.5 tons per day reductions by December 2014 to meet the minimum AQMP obligation and will submit the remaining at later date no later than December 2019. Staff believes that compliance with a facility cap still provides the facilities more operational flexibilities than being subject to stringent requirements in command-and-control rules and regulations.

4) Shaving Methodology

Facilities with no equipment subject to new BARCT commented that the uniform shave was not equitable, would create significant difficulties for them to stay in compliance, and indicated that they had limited ability to buy RTCs from large facilities. While WSPA and the refineries that are subject to new BARCT argued strongly during the rule development process in 2008-2009 for the use of a shave methodology that was consistent with that used during the 2005 NOx RECLAIM amendment. During the later phase of the rule development process, they commented that staff should use the 2005 as baseline for the shave, not shave the 1.98 tpd RTCs converted from ERCs and portion reserved for Clean Fuel projects, and not set new BARCT for SRU/TGs and cement kilns.

Staff's Response: Because of the non-uniform emissions and RTC distributions in ~~characteristics of~~ the SOx RECLAIM market (11 major facilities hold 87% RTCs and contribute more than 94% of emissions, and the remaining 21 facilities hold only 6% RTCs and contribute about 6% of emissions), a uniform percent shave of ~~64~~52% across the board ~~may not be~~is not the ultimate solution. The 21 facilities that have no equipment subject to the new BARCT cannot reduce their emissions further, cannot sustain operation since they had limited ability to buy RTC from large facilities, and therefore cannot remain in compliance after the shave. To keep the 21 facilities active in the SOx market, staff is proposing to not shave the RTC holdings for these facilities if the RTC holdings are below their initial allocations provided to them at the start of the RECLAIM program. However, the amount of RTC holdings above their initial allocation will be shaved at the same rate as other 11 facilities and investors. With this approach, staff estimated that instead of a ~~64%~~52% shave across the board, the 11 facilities will have a shave of ~~67.5%~~55%, ~~and the 21 remaining facilities will have a shave of 4%. Alternatively,~~ 18 of the 21 facilities ~~may~~will be exempt totally from the shave, and 3 of the 21 facilities that have RTC holdings above their initial allocations ~~may~~will be shaved up to the initial allocation levels. ~~Staff may refine the alternative shave approach in the future to address~~

~~comments and input from the stakeholders.~~ Any trading from August 29, 2009 to the Governing Board hearing date will also be shaved to ensure that the 14 facilities subject to shave as of August 29, 2009 will not sell their RTC holdings to a third party investor or any of the remaining 18 facilities to avoid the shave.

Staff used the 1997 baseline to be consistent with the approach used in the NOx RECLAIM adopted by the Governing Board in 2005. Using the audited 1997 baseline emissions, grown to 2019 based on assumptions embedded in the 2007 AQMP, would result in 55% shave to the 11 facilities, including the refineries and investors, whereas using the audited 2005 baseline would result in 59% shave. The emission profile changed significantly since 1997. Active facilities have purchased RTCs from shutdown facilities to partially sustain/expand their facility operations. These investments would be wasted if the shave is based strictly on today BARCT and current emission profile. [4] However, the SRU/TGs and cement kilns should not be exempt from BARCT because retrofit control technologies are available for these sources. The 1.98 tons per day RTCs converted from ERCs at the start of the RECLAIM program are not inherently protected from the shave since their values were reduced at approximately 35% in Tier II, and furthermore, even ERCs for non-RECLAIM facilities are often recalled and reduced in values.

Draft Staff Report

The attached revised Draft Staff Report includes the following information:

- BARCT determinations;
- Cost-effectiveness;
- Summary of consultants' analyses;
- Method of determining RTC reductions and amount estimated;
- Timing of reductions; and
- Preliminary methods of applying reductions.

Draft Staff Report changes since ~~June 23, 2009~~December 2009

Since the release of the draft Staff Reports in the Public Workshop conducted on June 23, 2009, and the Informational Hearing on January 8, 2010, staff modified the document as follows:

- Removed control technology recommendations with cost effectiveness larger than $50 K per ton (1 for FCCU, 2 for SRU/TGTUs, 1 for Boilers/Heaters) from the cost analysis, emission and RTC reduction analyses,
- Added achieved-in-practice information,
- Added a draft analysis on water and waste, and
- Provided responses to the comments received in the Public Workshop,
- Included analysis by Norton Engineering (NEC) and a cost effectiveness analysis based on NEC's recommendations,
- Used the audited 1997 emissions in the analysis for RTC shave,
-

[4] Total RTCs from shutdown facilities as of today date are 1.42 tons per day of which investors have 0.83 tons per day. The amount of RTCs hold by investors will be shaved at the same rate as the RTCs hold by the 11 facilities that have equipment subject to BARCT.

- Excluded the emission reductions of 0.85 tpd estimated from boilers/heaters since the proposed BARCT limit is retained at the previous BARCT level of 40 ppmv, and
- Extended the implementation period from 2017 to 2019 and reflected growth embedded in the 2007 AQMP.

~~Other minor changes are:~~

- ~~Reorganized the report for clarity,~~
- ~~Revised the 1997-1998 inventory for sulfuric acid plants from 0.75 tpd to 1.28 tpd,~~
- ~~Revised inventory for boilers/heaters from 7.08 tpd to 6.5 tpd,~~
- ~~Revised growth factor for category "Others" from 1 to 1.07,~~
- ~~Revised BARCT proposed level for SRU/TGTUs from to 4.72 lbs/hr to 5.28 lbs/hr, and control factor from 0.56 to 0.63; coke calciner from 0.07 lbs/ton to 0.11 lbs/ton, and control factor from 0.03 to 0.05; cement kiln from 0.035 to 0.04 lbs/ton, and~~
- ~~Made some grammatical and other general corrections.~~

Staff will continue to revise the draft Staff Report as needed in the future.

Chapter 1 - Background

1.1 Legislative Authority

The California Legislature created the Air Quality Management District (AQMD) in 1977 (the Lewis-Presley Air Quality Management Act, Health and Safety Code Section 40400 et seq.) as the agency responsible for developing and enforcing air pollution control rules and regulations in the South Coast Air Basin (Basin). By statute, the AQMD is required to adopt an Air Quality Management Plan (AQMP) demonstrating compliance with all state and federal ambient air quality standards for the Basin (Health and Safety Code (H&SC) §40460(a)). In addition, the AQMD must adopt rules and regulations that implement the AQMP (H&SC §40440(a)).

The California Clean Air Act (CCAA) also requires the AQMD to achieve and maintain state standards by the earliest practicable date and for extreme non-attainment areas and to implement all Best Available Retrofit Control Technologies (BARCT) for existing sources. H&SC §40406 specifically defines BARCT as "…best available retrofit technology means an emission limitation that is based on the maximum degree of reduction achievable taking into account environmental, energy, and economic impacts by each class or category of source."

1.2 Fine Particle Regulation and SOx Control

Scientific studies have found an association between exposure to particulate matter and significant health problems, including: aggravated asthma; chronic bronchitis; reduced lung function; irregular heartbeat; heart attack; and premature death in people with heart or lung disease. Individuals particularly sensitive to fine particle exposure include older adults, people with heart and lung disease, and children.

In July 1997, the U.S. EPA promulgated the National Ambient Air Quality Standards for Fine Particles (PM-2.5). The annual standard is a level of 15 micrograms per cubic meter (µg/m3) based on a 3-year average of annual mean PM2.5 concentrations. The 24-hour standard is a level of 65 µg/m3, based on a 3-year average of the 98th percentile of 24-hour concentrations. In September 2006, EPA significantly strengthened the previous daily fine particle standard from 65 µg/m3 to 35 µg/m3. This standard increases protection of the public from short-term exposure to fine particles.

There are multiple areas across the country exceeding the federal PM2.5 standards. Unfortunately, Southern Californians are burdened with a disproportional share of the PM2.5 exposure estimated to be 52 percent of the nation wide exposure resulting in approximately 5,400 premature ~~death~~deaths annually.

In March 2007, EPA issued a final rule, known as the *Clean Air Fine Particle Implementation Rule*, requires non-attainment areas to meet PM 2.5 standards by 2010. The Basin is classified as a non-attainment area and the District must develop an Air Quality Management Plan by 2008 to address the implementation processes to substantially reduce PM2.5 in order to meet the PM2.5 standards by 2010. The attainment date of 2010 may be extended for up to five ~~years,~~years; however the District must achieve PM2.5 standards as expeditiously as possible, no later than 2015. The recently adopted AQMP revision in 2007 serves as the region's attainment demonstration to the federal ozone and PM2.5 standards and includes a formal request to the U.S. EPA to extend the PM2.5 attainment date to 2015.

Five main types of pollutants contribute to ambient PM2.5 concentrations: direct PM2.5 emissions, sulfur dioxide, nitrogen oxides, ammonia and volatile organic compounds. The effect of reducing emissions of each of these pollutants varies by areas depending on the composition, concentrations of these pollutants and other area-specific factors. The EPA's *Clean Air Fine Particle Implementation Rule* requires the District to implement all reasonably available control measures (RACM) and reasonably available control technology (RACT), considering economic and technical feasibility and other ~~factors, that~~factors that are needed to show that the area will attain the fine particle standards as expeditiously as practicable. In this *Clean Air Fine Particle Implementation Rule*, the U.S. EPA specifically requires the non-attainment areas to evaluate all control measures to reduce direct PM2.5 emissions, as well as PM2.5 precursors, especially SOx. While the 2007 AQMP lays out a multi-pollutant control strategy to demonstrate attainment with the federal PM2.5 standards, it identifies NOx and SOx reductions by far as the two most effective tools in reaching attainment with the PM2.5 standards.

1.3 Current RECLAIM Program

On October 15, 1993, the District's Governing Board adopted the RECLAIM program and Regulation XX. Regulation XX includes 11 rules that specify the applicability, NOx and SOx allocations, general requirements, as well as monitoring, reporting, and recordkeeping requirements. The RECLAIM program started with 41 SOx and 392 NOx facilities in 1993. By the end of 2005 compliance year, the program includes 33 SOx and 304 NOx facilities.

Under the RECLAIM program, facilities are issued SOx and NOx annual allocations, or also known as facility caps. The facility caps declined annually to reflect the levels of BARCT that were envisioned to be in place at the RECLAIM facilities. To meet the annual declining allocation, RECLAIM facilities have the flexibility of installing pollution control equipment, changing operations, or purchasing RECLAIM Trading Credits (RTCs). It was envisioned that a BARCT analysis be conducted every three years to capture any advancement in control technology and to assure that the RECLAIM program would achieve emission reductions as expeditiously as possible.

Throughout the years, there have been a number of amendments to the RECLAIM rules. In January 2005, a BARCT analysis was re-conducted for NOx, and as a result of this analysis, the

RECLAIM rules were amended and the NOx annual allocations previously given to the NOX RECLAIM facility were further reduced by approximately 20% to reflect BARCT.

For SOx, the annual allocations given decline annually from 1993 until 2003, and remain constant since 2003. The 2003 SOx allocations reflected the BARCT levels envisioned for SOx in 1993. BARCT analysis for SOx has not been reevaluated since 1993, and is reevaluated with this proposed amendment.

1.4 Control Measure CMB-02

Control Measure CMB-02 estimated that BARCT would be implemented to achieve approximately 3 tons per day SOx emission reductions from 2011 to 2014. The control measure estimated that reducing sulfur content in refinery fuel gas could achieve approximately 1.6 tons per day SOx; and reducing SOx emissions from fluid catalytic cracking units could achieve 1.3 tons per day SOx. It was expected that the control measure implementation may either affect all SOx RECLAIM facilities or only affect the facilities that have highest SOx emissions and that can employ BARCT. During the rulemaking process, it was envisioned that staff will also explore the feasibility to incorporate the control concept of Control Measure MCS-01 - Facility Modernization to achieve reductions beyond 2014.

1.5 Affected Facilities

Currently, there are 32 facilities in the SOx RECLAIM Program. Six of the 32 facilities are refineries with substantial operational capacities compared to 150 refineries in the U.S, and Chevron and BP are the two largest refineries in the state of California based on the operational capacities reported. [5] These 32 RECLAIM facilities have SOx emissions greater than or equal to four tons per year in 1990 or any subsequent year. SOx facilities in the RECLAIM program have a wide range of equipment such as Fluidized Catalytic Cracking Units (FCCU), furnaces, kilns, sulfuric acid plants, tail gas units, boilers, heaters, internal combustion engines, and gas turbines. The emission inventory of these facilities and the top emitters at these facilities is discussed in Chapter 1, Section 1.7.

[5] Operable capacities of six refineries and their ranks compared to 150 refineries in the U.S.

Refinery	**Capacity (Barrels per Day)**	**Rank in the U.S.**
Chevron	279,000	17
BP West Coast Products LLC	265,000	18
ExxonMobil	149,500	47
ConocoPhillips	139,000	52
Tesoro	96,860	64
Ultramar Inc.	80,887	71

Reference: The U.S. Energy Information Administration, www.eia.doe.gov/neic/rankings/refineries.htm, July 2010. Refinery individual crude capacity data were reported by individual refinery as of January 1, 2009. See Appendix E.

1.6 2007 Air Quality Management Plan

The 2007 Air Quality Management Plan (AQMP) was based on the 2002 base year inventory. In the 2007 AQMP, RECLAIM facilities were reported to emit a total of 12 tons per day SOx as shown in Table 1-1. In 2002, the SOx emissions from RECLAIM represented more than 50% of the total SOx emissions from stationary sources, and 23% of the total SOx emissions from the entire basin.

TABLE 1-1

Summary of Emissions ~~By~~by Major Source Category (2002 Base Year) (Tons per Day)

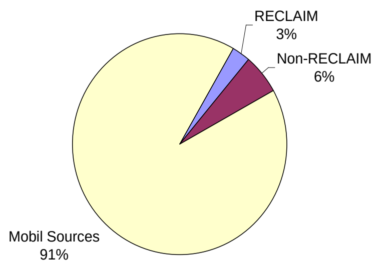
Source Category	NOx	SOx
Stationary Sources		
Fuel Combustion	35	2
Waste Disposal	2	0
Cleaning and Surface Coatings	0	0
Petroleum Production and Marketing	0	7
Industrial Processes	0	0
Solvent Evaporation		
Consumer Products	0	0
Architectural Coatings	0	0
Others	0	0
Misc. Processes	27	0
RECLAIM Sources	**29**	**12**
Total Stationary Sources	**93**	**22**
Total Mobile Sources	**1000**	**31**
TOTAL	**1093**	**53**

Reference: 2007 AQMP. The actual emissions from RECLAIM facilities of 12 tpd were also reported in the "Annual RECLAIM Audit Report for the 2002 Compliance Year", dated March 5, 2004. Total RTCs (allocations and converted ERCs) were reported to be 13 tpd in the 2002 RECLAIM Audit Report.

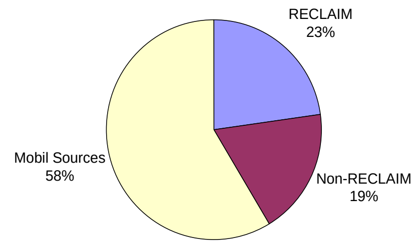
Data presented in Table 1-1 and Figure 1-1 present a sharp distinction between the ~~distribution~~distributions of NOx versus SOx emissions in the basin, and explain the importance of undertaking a BARCT reassessment for RECLAIM facilities in this amendment of Regulation XX. As shown in Table 1-1 and Figure 1-1, the RECLAIM facilities contribute to only about 3% of the NOx emissions in the entire South Coast Air Basin (Basin). A majority of NOx emissions in the Basin comes from mobile sources. In contrast, the RECLAIM facilities contribute to more than 23% of SOx emissions in the Basin and more than 50% of SOx emissions from stationary sources.

The top 10 ranking sources of SOx emissions in the basin in 2002, 2014 and 2023 are shown in Table 1-2. SOx emissions from RECLAIM facilities are ranked #2, second only to ships and commercial boats. Given the effectiveness of the SOx reduction in improving PM2.5 air quality and ultimately reaching the federal PM2.5 standards, searching for additional emission reductions in RECLAIM category sources becomes an important effort.

FIGURE ~~2~~1-1
NOx and SOx Emission Distribution (2002 Baseline)



NOx Emissions



SOx Emissions

TABLE 1-2
Top Ten Ranking of SOx Emissions ~~From~~from Highest to Lowest

	2002 Base Year	2014 Base Year	2023 Base Year
1	Ships & Commercial Boats	Ships & Commercial Boats	Ships & Commercial Boats
2	RECLAIM Sources	RECLAIM Sources	RECLAIM Sources
3	Non-RECLAIM Sources	Aircraft	Aircraft
4	Heavy-Duty Diesel Trucks	Manufact/Industrial Combustion	Manufact/Industrial Combustion
5	Aircraft	Light-Duty Passenger Cars	Light-Duty Passenger Cars
6	Trains	Light-Duty Trucks	Light-Duty Trucks
7	Off-Road Equipment	Service/Commercial Combustion	Service/Commercial Combustion
8	Light-Duty Passenger Cars	Non-RECLAIM Sources	Non-RECLAIM Sources
9	Manufact/Industrial Combustion	Waste Burning & Disposal	Waste Burning & Disposal
10	Light-Duty Trucks	Residential Fuel Combustion	Residential Fuel Combustion

Reference: 2007 AQMP. Note that Non-RECLAIM sources are sources that are not included in the RECLAIM program such SOX emissions emitted from flares or generated under upset conditions.

The 2007 AQMP calls for significant reductions of SOx from both stationary and mobile sources by 2014. As shown in Table 1-3, a regional modeling in the 2007 AQMP indicates that an overall emission reduction of 24 tons per day SOx is needed to meet the particulate standard in 2014. In that 24 tons per day reduction, mobile source control measures from California Air Resources Board and the District can potentially reduce 21 tons per day. The remaining 3 tons per day reductions comes from the stationary source control measure for RECLAIM facilities. A BARCT reassessment for SOx is therefore essential to identify the potential sources that can generate the 3 tons per day SOx reduction required for 2014.

TABLE 1-3
Emission Reductions for 2014 Based On
Average Annual Emissions Inventory (tons per day)

Sources	SOx
Year 2014 Baseline	43
Emission Reductions:	
• District's Short Term/Mid-Term Stationary Source Control Measures	**3**
• CARB's Proposed State Strategy	20
• District's Proposed Mobile Source Control Measures	1
Total Reductions (All Measures)	24
2014 Remaining Emissions	19

Reference: Table 4-10 of 2007 AQMP

1.7 2005 Annual Emissions Report

RECLAIM facilities reported a total of 10 tons per day SOx from January to December 2005. As shown in Table 1-4, the top twelve SOx emitting facilities emitted 9.47 tons per day SOx, which are about 95% of total emissions from RECLAIM universe. The top 11 emitting facilities where staff will focus in to find the sources of emission reductions include:

– Six refineries: BP, ConocoPhillips, Chevron, ExxonMobil, Ultramar, and Equilon (Tesoro.)
– Two sulfuric acid plants: Rhodia Inc. and ConocoPhillips
– One coke calciner plant: BP located in Wilmington
– One cement manufacturing plant: California Portland Cement Co.
– One container glass manufacturing plants: Owns Brockway Glass Container Inc.

TABLE 1-4
SOx Emissions at RECLAIM Facilities (Compliance Year 2005)

Facility ID	Facility Name	Cycle	Emissions (tons per year)	Emissions (tons per day)	Cumulative Percentage
131003	BP WEST COAST PROD.LLC BP CARSON REFINERY	2	679.4	1.86	19%
800363	CONOCOPHILLIPS COMPANY	2	421.2	1.15	30%
114801	RHODIA INC.	1	410.7	1.13	42%
800370	EQUILON (Now is TESORO)	1	363.6	1.00	52%
800030	CHEVRON PRODUCTS CO.	2	362.5	0.99	62%
800089	EXXONMOBIL OIL CORPORATION	1	333.5	0.91	71%
800026	ULTRAMAR INC	1	312.8	0.86	80%
800362	CONOCOPHILLIPS COMPANY	1	210.7	0.58	85%
131249	BP WEST COAST PRODUCTS LLC,BP WILMINGTON	1	130.1	0.36	89%
800181	CALIFORNIA PORTLAND CEMENT CO	2	100.5	0.28	92%
7427	OWENS-BROCKWAY GLASS CONTAINER INC	1	74.7	0.20	94%
108701	SAINT-GOBAIN CONTAINERS, INC. (Not in Operation)	1	55.9	0.15	95%
	OTHER RECLAIM FACILITIES	1 and 2	165.0	0.45	100%
	Total		**3621**	**9.92**	

Reference: Based on the 2005 Annual Permit Emissions Report (January 2005 – December 2005), the emissions reported for 2005 were 9.92 tons per day. Please note that the audited 2005 emissions were 3,663 lbs (10.04 tons per day) as shown in the 2010 Annual RECLAIM Audit Report, March 5, 2010.

Table 1-5 shows the distribution of SOx emissions with respect to the equipment/processes at RECLAIM facilities. As shown in Table 1-5, top emitters at RECLAIM facilities include fluid catalytic cracking units, sulfur recovery and tail gas treatment units, refinery boilers and heaters burning refinery gases, coke calciner, cement kilns, sulfuric acid absorption tower and glass melting furnaces. Staff will focus in reassessing BARCT for these top emitters which emit more than 80% of SOx emissions at RECLAIM facilities.

TABLE 1-5
Distribution of SOx Emissions at RECLAIM Facilities

Equipment/Processes	Percentage of Emissions
Fluid Catalytic Cracking Units	33%
Sulfur Recovery & Tail Gas Units	10%
Refinery Process Heaters and Boilers	31%
Cement Kilns – Glass Melting Furnaces	7%
Sulfuric Acid Manufacturing	12%
Other Miscellaneous Processes/Equipment	7%

Reference: 2005 baseline emissions

Table 1-6 shows SOx emissions reported from 2002 to 2007, grouped by compliance year and calendar year (e.g. SOx emissions reported for the 2003 compliance year were the emissions reported from January 1, 2003 – December 31, 2003 for Cycle 1 RECLAIM facilities, and from July 1, 2003 – June 31, 2004 for Cycle 2 facilities. SOx emissions reported for the 2003 calendar year were the emissions reported from January 1, 2003 – December 31, 2003 for both Cycle 1 and Cycle 2 facilities.) The average reported emissions from 2003 – 2007 compliance year were approximately 10 ~~tpd (~~tpd (Staff did not include year 2002, and the years before 2002 in the average, because the Tier II shave started in 2003.) Year 2005 emissions are closest to the average, and thus stand out to be the most representative emissions for the period from 2003 – 2007.

TABLE 1-6
SOx Emissions Reported by RECLAIM Facilities from 2002 – 2007

Year	**SOx Emissions by Compliance Year**	**SOx Emissions by Calendar Year**
	(tpd)	**(tpd)**
2002	11.84	12.17
2003	10.56	11.08
2004	9.85	9.85
2005	**9.92**	**10.13**
2006	9.81	10.24
2007	10.27	
Average (2003 - 2007)	**10.08**	

Chapter 2 – Best Available Retrofit Control Technology

2.1 Definition

Best Available Retrofit Control Technology (BARCT) is defined in California Health and Safety (H&S) Code §40406 as:

> *"... an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, & economic impacts by each class or category of source."*

In addition, Section §40440(b~~)(~~) (1) requires the District to adopt rules that requires the use of BARCT for existing sources:

> *"Require the use of best available control technology for new or modified sources and the use of best available retrofit control technology for existing sources."*

The BARCT analysis procedure for RECLAIM is identical to any BARCT analysis procedure used in developing a command-and-control rule. In RECLAIM, however, the BARCT levels are mainly used for assessing programmatic RECLAIM Trading Credit (RTC) reductions. Unlike other facilities that are subject to a command-and-control rule, RECLAIM facilities are not required to meet the BARCT levels at all times. RECLAIM facilities are provided the flexibility to meet the programmatic reductions by various means, such as installing control devices or buying RTCs.

It should be noted that California H&S Code §39616 requires a market incentive program to achieve an equivalent or greater level of emission reductions at an equivalent or lower cost as would have been achieved under a command-and-control rule. Since the adoption of RECLAIM in 1993, staff has not conducted any BARCT analysis for SOx. Starting with the 2003 AQMP, staff committed to conduct a BARCT analysis for RECLAIM facilities every three years to assure that RECLAIM and non-RECLAIM facilities are subject to the same BARCT standards based on state-of-the-art control technologies.

2.2 BARCT Evaluation Process

In order to identify BARCT meeting the definition of California Health and Safety (H&S) Code §40406, staff conducted the following procedure:

2.2.1 Identify Technology That Can Achieve Maximum Degree of Reduction

To identify technology that can achieve maximum degree of reduction for this project, staff conducted a thorough and extensive research of the:

1. Control technology (both existing technology and potential future technology) from literature research, consultations with manufacturers/vendors, and expert consultants;

2. Federal, state, or other air pollution control district or agency rules/regulations; and

3. U.S. EPA RACT/BARCT/LAER Clearinghouse, CARB database, and other state and local district permitting database to search for recent BACT or BARCT implementation.

It should be noted that in the rule making process staff is not obligated or limited to look at fully commercialized available technologies. Sometimes staff is called upon to develop technology forcing rules. In this situation, staff can consider technology that has not been applied to full scale operations, and provide sufficient time in the rule language to assist the technology to reach maturity. In addition, staff can develop alternative compliance provisions to handle situations where the technology cannot be fully developed.

Staff will consider feasible retrofit control technology, which is a technology that has been previously installed and operated successfully at a similar type of source, or has practical potential for application to the source (i.e. has been successfully applied to similar sources with similar gas stream characteristics).

Staff will also consider currently available retrofit control technology, which is a control technology that 1) is being offered commercially by vendors, or 2) is in commercial demonstration or licensing. Technologies that are in development and testing stages are generally classified as not currently available, but if available in the future, will be considered in the BARCT determination as well.

In July 2008, staff awarded two contracts to two individual contractors and a sub-contractor to conduct an independent analysis on feasible/available control technologies and assess costs and cost effectiveness of control technologies. The contractors were required to identify at least two available control technology manufacturers/vendors for each of the seven categories of sources. The contractors were also asked to collect the manufacturers' performance guaranteed letters. The results are of staff's work and consultants' analyses are summarized in Chapter 3 – Chapter 9 of this report.

A summary of staff's review on federal, state or other air pollution control districts' regulatory requirements is shown in Appendix B of this report. [6]

[6] In addition, please also see staff's review of regulatory requirements shown in Appendix VI of the 2007 AQMP – RACM Demonstration.

2.2.2 Evaluate Control Effectiveness

After the technically feasible and available control technologies were identified, staff evaluated the control effectiveness of the control technology using the control efficiency, or the outlet SOx concentration, or the emission factor reported for each control technology. These control effectiveness information was obtained by considering data available through permitting, source testing, engineering estimates, or performance guarantees by the control manufacturers/vendors.

As part of the contracts, the contractors were required to assess the levels of emission reductions that could be achieved from at least two different types of control technology. The results are summarized in Chapter 3 – Chapter 9 of the Staff Report.

2.2.3 Conduct Top-Down Cost Effectiveness Analysis

After the control effectiveness is established, a top-down cost effectiveness analysis starting with the most effective control technology was conducted to provide information on emission reductions and cost effectiveness associated with different control technologies and different levels of control.

The top-down cost effectiveness analysis must consider site-specific, physical limitation, as well as operational characteristics of the equipment at the facilities. Equipment costs, installation costs, annual operating costs, the useful life of the control equipment are all captured in this analysis to generate a cost-effectiveness factor in dollars per ton of pollutants reduced.

Staff did not conduct a cost effectiveness analysis for this project but selected to contract this task to two contractors and a subcontractor. Their extensive and detailed cost analyses are summarized and referenced in Part II of the Staff Report. In most parts, staff was in agreement with the contractors' analyses and used their costs and cost effectiveness in the scenario studies discussed in Chapter 12. However, in some few scenarios, staff adjusted the consultants' estimate to reflect the actual conditions at the facilities.[7]

Establishing a cost-effectiveness factor allows a comparison of control technologies. Using the contractors' costs information, staff estimated the following four types of cost-effectiveness:

1) Individual cost effectiveness for a specific emitting source (e.g. cost effectiveness for each FCCU);
2) Average cost effectiveness for the category of source (e.g. average cost effectiveness for five FCCUs in the Basin);
3) Average cost effectiveness for the entire project; and

[7] For example, for coke calciner, the consultant used maximum operational parameters to design the control system, estimated costs, emission reductions, and cost effectiveness. Staff used the estimated costs from the consultant's analysis but estimated cost effectiveness based on actual emission reductions not emission reductions estimated based on the designed operational parameters.

4) Incremental cost-effectiveness for the entire project.

The individual cost-effectiveness is defined as the present worth value of the control technology divided by the total quantity of pollutants removed during the life time of a control technology. The average cost effectiveness is an average of all control technologies, or an average of all control technologies for all sources in the project. The incremental cost-effectiveness is a comparison of the cost and performance level of a control technology to a next more stringent option.

There is no bright line cut-off of what cost effectiveness in dollars per ton should be considered as cost effective. The cost-effectiveness factor remains a relative measurement factor.

The top down analysis conducted by the contractors and their results are summarized in Part II of the Staff Report.

In addition to the top down analysis conducted by the contractors, staff conducted a scenario analysis presented in Chapter 12 where staff estimated the emission reductions and cost effectiveness for four scenarios of control ranging from the most stringent set of control to the least stringent set of control. From this analysis, staff selected a scenario that best reflected BARCT, "*… maximum degree of reduction achievable, taking into account of ….economic impacts by each class or category of source.*"

2.2.4 Select Best Available Retrofit Control Technology (BARCT)

The H&S Code 40406 requires ~~staff~~the District to take into account environmental, energy and economic impacts during the BARCT selection process. The energy impact of each evaluated control technology is the energy penalty or benefit resulting from the operation of the control technology at the source. An example of the energy impact includes the increase (or decrease) in energy consumption at the source.

The environmental impacts are evaluated to determine whether a particular control technology has any impacts, either positive or negative, to the environment. An example of the environmental impact is the generation of wastewater discharge and solid waste.

The economic impacts (costs and cost effectiveness) are evaluated to determine the impacts of staff proposal on each affected facility and to the economy of the basin as a whole.

Staff asked the consultants to identify and quantify the environmental effects or impacts (water demand, wastewater treatment, solid waste, energy consumption) and provide information on any hazardous materials and hazardous waste, if known for each SOx reduction technique or technology evaluated. The consultants' results for this analysis are in their final reports.[8]

---

[8] The consultants' estimates are accurate except for the reported water demand for the SRU/TG's wet gas scrubbers. The figures reported in the final report are not the same as the numbers reported in the draft report. It is an oversight in transferring the numbers, only for the SRU/TGs. Staff contacted the wet gas scrubber manufacturers and directly gathered the water demand information for SRU/TGs as explained in a footnote in Chapter 11.

~~The water demand and wastewater reported by the consultants were highly overestimated for SRU/TGTUs, and staff revised these data accordingly as discussed in Chapter 10 of the Staff Report.~~

In addition, the consultants were asked to conduct an analysis on concurrent effect on other air pollutants, and made comments and recommendations if there were technologies capable of reducing SOx, and concurrently reducing (or increasing) PM2.5, and/or CO2. The consultants indicated that wet gas scrubbers should have a positive effect on particulate emissions and minimal impact on NOx, ammonia, and volatile organic compound. Fine particulate impact will be lessened by reducing SO2 emissions which is PM2.5 precursor.

After considering environmental, energy, and economic impacts of each category of seven sources identified by staff, the contractors proposed the BARCT levels shown in Table 2-1.

Staff was in agreement with the consultants' recommendation for FCCUs, SRUs/TGs, refinery boilers/heaters, coke calciner, and sulfuric acid manufacturing, however, staff differed in setting the BARCT limits for glass melting furnace and cement kilns/coal-fired boiler, and further removed the scenarios where the cost effectiveness was lower exceeding >$50K per ton. The proposed BARCT levels recommended by staff and the consultants are shown in Table 2-1. Refer to Chapter 3 – Chapter 9 for additional information and BARCT evaluation.

Table 2-1
BARCT Levels Recommended by the Consultants and AQMD

Basic Equipment	Consultants' Recommendation	AQMD's Recommendation
Fluid Catalytic Cracking Units	5 ppmv	5 ppmv
SRUs/TGs	Incinerated tail gas: 5 ppmv; Non incinerated tail gas: 10 ppmv H2S & 300 ppmv non H2S	Incinerated tail gas: 5 ppmv; Non incinerated tail gas: 10 ppmv H2S & 300 ppmv non H2S
Refinery Boilers/Heaters	40 ppmv	40 ppmv
Calciner, Petroleum Coke	10 ppmv	10 ppmv
Sulfuric Acid Mfg	10 ppmv	10 ppmv
Container Glass Melting Furnace	1-2 ppmv (99% control)	5 ppmv
Cement Kiln & Coal-Fired Boiler	1-2 ppmv (95% control)	5 ppmv

Additional CEQA, Socioeconomic, and market analyses are being conducted and staff will continue to readjust the proposed BARCT levels if needed to satisfy the requirement of the H&S Code.

Chapter 3 – Fluid Catalytic Cracking Units

3.1 Process Description

There are six refineries that operate six fluid catalytic cracking units (FCCU) in the District: Chevron, BP West Coast, ExxonMobil, ConocoPhillips, Ultramar and Tesoro. The FCCUs are classified as major sources of emissions in RECLAIM, and as such, the emissions from FCCUs are required to be monitored with continuous emission monitoring system (CEMS), and reported on a daily basis electronically to the District. A brief description of the process is presented below. The FCCU capacities in barrels fresh feed per calendar day reported to the U.S. Energy Information Administration are as follows. BP and ExxonMobil operate the two largest FCCUs in the state of California in terms of barrels fresh feed per calendar days processed.

BP	101,500 barrels per calendar day
ExxonMobil	83,500 barrels per calendar day
Chevron	66,500 barrels per calendar day
Valero	52,200 barrels per calendar day
ConocoPhillips	48,700 barrels per calendar day
Tesoro	31,958 barrels per calendar day

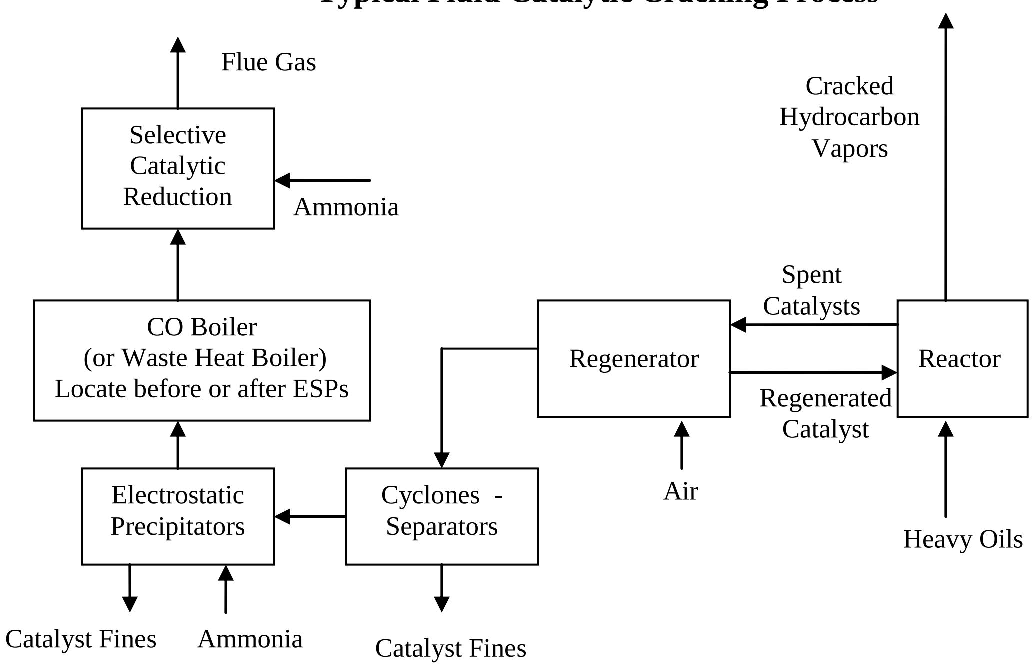
The FCCU is the most important and widely used refinery process for converting heavy oils into more valuable gasoline and lighter products. The process uses a very fine catalyst that behaves as a fluid when aerated with a vapor. The fluidized catalyst is circulated continuously between a reactor and a regenerator and acts as a vehicle to transfer heat from the regenerator to the oil feed in the reactor. The cracking reaction is endothermic and the regeneration reaction is exothermic. A schematic of a fluid catalytic cracking unit (FCCU) is shown in Figure 3-1.

The fresh feed is preheated by heat exchangers to a temperature of 500-800 degree Fahrenheit and enters the FCCU at the base of the feed riser where it is mixed with the hot regenerated catalyst. The heat from the catalyst vaporizes the feed and brings it up to the desired reaction temperature. The mixture of catalyst and hydrocarbon vapor travels up the riser into the reactor. The cracking reaction starts in the feed riser and continues in the reactor. Average reactor temperatures are in the range of 900-1000 degree Fahrenheit. As the cracking reaction progresses, the catalyst surface is gradually coated with carbon (coke), reducing its efficiency. While the cracked hydrocarbon vapors are routed overhead to a distillation column for separation into lighter components, the oil remaining on the catalyst is removed by steam stripping before the spent catalyst is cycled to the regenerator.

In the regenerator, the coke is burned off with air and the spent catalyst is reactivated. The regenerator can be designed and operated to either partially burn the coke on the catalyst to a mixture of carbon monoxide (CO) and carbon dioxide (CO_2), or completely burn the coke to CO_2. The regenerator temperature is carefully controlled to prevent catalyst deactivation by overheating and to provide the desired amount of carbon burn-off. This is done by controlling the air flow to give a desired CO_2/CO ratio in the exit flue gases or the desired temperature in the regenerator. The flue gas containing a high level of CO is routed to a supplemental-fuel fired CO boiler if needed to completely burn off the CO to CO_2. Generally, FCCUs operate in a completely burn mode; and in this scenario, the CO boiler might be used as a heat recovery device without any supplemental fuel. The regenerated catalyst is generally steam-stripped to remove adsorbed oxygen before being cycled back to the reactor. The regenerator exit temperatures for catalyst are about 1,200-1,450 degree Fahrenheit.

It is during the regeneration cycle that some of the catalyst is lost in the form of catalyst fines. The catalyst fines escape the regenerator in both the flue gas and the hydrocarbon vapor stream going to the fractionation column. The FCCU is a major source of sulfur oxides, nitrogen oxides and particulate matter in the refinery. To control particulate emissions, flue gas from the regenerator is routed through a series of ~~cyclones and~~cyclones and electrostatic precipitators. Selective catalytic reduction can be used to reduce nitrogen oxides emissions. The control options for sulfur oxides are discussed in Section 3.3 below.

FIGURE 3-1
Typical Fluid Catalytic Cracking Process



3.2 Current Allocations and Emissions

3.2.1 Allocations

In 1993, the six refineries in the basin were issued emission allocations to their FCCUs based on an emission factor (also known as Tier I emission factor) of 13.7 lbs SOx per thousand barrels refinery feed. The activity of each FCCU used in the allocation determination in 1993, and the emissions allocated to each FCCU are listed in Table 3-1. The total Tier I allocations provided for the six FCCUs are 2.17 tons per day.

3.2.2 Emissions

Since FCCUs are classified as major sources in RECLAIM, the SOx emissions from the FCCUs are monitored with CEMS and reported on a daily basis to the District. The total annual emissions from January 2005 – December 2005 from the FCCUs is about 3.55 tons per day as shown in Table 3-2.

The FCCUs at RECLAIM facilities are not subject to any specific concentration or emission rate standards. RECLAIM facilities are given the flexibility to operate their equipment as long as the total emissions from the facility are at or below the facility emission caps. The allocations provided to the FCCUs since 1993 have not been adjusted even though there are commercially available technologies that can be used to further reduce SOx emissions from the FCCUs. In addition, the capacity of each FCCU may increase since the level reported in 1993, which warrants for a need to upgrade the capacity of the control device.

TABLE 3-1
SOx Allocations for FCCUs

Facility	Peak Year	Emission Factor (lbs/1000 barrels)	Tier I Allocations (lbs/year)	Tier I Allocations (tons/day)
A	1992	13.7	297,345	0.41
B	1990	13.7	414,233	0.57
C	1988	13.7	188,545	0.26
D	1992	13.7	374,037	0.51
E	1991	13.7	127,684	0.18
F	1990	13.7	172,291	0.24
			Total	**2.17**

Reference: Allocation files for each facility developed based on reported data in 1993.

TABLE 3-2
Current SOx Emissions from FCCUs

Facility	2005 SOx Emissions (tons/day)	2006 SOx Emissions (tons/day)	2007 SOx Emissions (tons/day)
A	0.39	0.36	0.33
B	1.03	0.70	0.71
C	0.96	1.00	0.97
D	0.31	0.27	0.20
E	0.25	0.28	0.18
F	0.61	0.89	0.56
	3.55	**3.50**	**2.95**

Note: The 2005 SOx emissions were from SCAQMD database for the period from January 2005 – December 2005. The 2006 and 2007 emissions were reported by the facilities through a Survey Questionnaire distributed by SCAQMD in 2008.

Based on responses from the facilities to the 2008 SCAQMD Survey Questionnaire, staff estimated that the six refineries were operated at the current emission rates listed in Table 3-3.

TABLE 3-3
Current SOx Emission Rates & Concentrations from FCCUs

SOx Outlet Concentrations (ppmv)	Emission Rate (lbs/1000 barrels feed)
Average 18 ppmv	10.99
Average 36 ppmv	21.68
35 ppmv – 95 ppmv	34.91
Average 12 ppmv	6.89
Average 11 ppmv	16.67
Average 58 ppmv	22.18
Average of 6 Refineries	**17.93**

Note: The SOx outlet concentrations at 0% O2 were either data reported by the facilities through the Survey conducted in 2008, or data in the source test results provided by SCAQMD source testing team.

3.3 Control Technology

The potential available control technologies to reduce SOx emissions from a FCCU are:

1. Processing of low sulfur feed stocks,
2. Feed hydro-treating,
3. Flue gas scrubbing,
4. Using SOx reducing additives,
5. Using combination of the above control technologies

Currently, the six refineries in the Basin have processed low sulfur feed stocks and use feed hydrotreating. Five refineries in the District have experimented with SOx reducing additives, and one refinery has chosen to install a wet scrubber to reduce SOx and PM concurrently.

3.3.1 SOx Reducing Catalysts

Type of Catalysts

Developed in the late 1970s, SOx reducing catalysts were initially alumina based. However, the alumina based catalysts were shown to be susceptible to deactivation. In 1980, it was found that the potential pick-up SO3 in the regenerator was substantially increased by replacing the pure alumina-based catalysts ~~with a magnesium-aluminate catalysts~~with magnesium-aluminate catalysts (1 mole of magnesium per 2 moles of aluminum). In 1990, Akzo Nobel invented hydrotalcite, and hydrotalcite-like, compounds to support up to 3 to 4 moles of magnesium per mole of aluminum. In 1997, Intercat Inc. patented a self-supporting hydrotalcite SOx reducing catalyst, named SOXGETTER®, and Grace-Davidson developed a DESOX® catalyst with significantly improved performance. In 2000, Intercat Inc. commercialized Super SOXGETTER® which is advertised to be 80% better than SOXGETTER®, and Grace-Davidson commercialized Super DESOX®, 35% better than DESOX® .[9, 10]

Mechanism for SOx Reduction

In general, SOx reducing catalysts remove SOx from the regenerator flue gas and release the sulfur as H_2S in the FCCU reactor through a three step mechanism:

In the regenerator, sulfur bearing coke is burned to SO_2; and in the presence of excess oxygen, a portion of SO_2 is converted to SO_3

$$S + O_2 \rightarrow SO_2$$
$$SO_2 + 1/2O_2 \rightarrow SO_3$$

The magnesium-based reducing catalysts "pick-up" SO_3 in the regenerator and form magnesium sulfate:

$$M_xO + SO_3 \rightarrow M_xSO_4$$

The magnesium sulfate recirculates back to the reactor, and reacts with hydrogen to form either magnesium sulfide and water, or magnesium oxide, and hydrogen sulfide:

$$M_xSO_4 + 4\,H_2 \rightarrow M_xS + 4H_2O$$
$$M_xS + H_2O \rightarrow M_xO + H_2S$$
$$M_xSO_4 + 4\,H_2 \rightarrow M_xO + H_2S + 3H_2O$$

The H_2S then exits the FCCU in the dry gas and must be removed by the sulfur recovery units. This increase in H_2S, 5% - 20%, can typically be managed within a refinery's operations.

Performance of SOx Reducing Catalysts

Control efficiency of SOx reducing additives depends on many factors such as 1) feed type, 2) starting SOx level, 3) catalyst type, 4) amount of catalysts added, and 5) FCCU's operating conditions. Manufacturers of SOx reducing catalysts generally use a proprietary computer model to estimate the performance of their products. Typical control efficiencies are reported to be in a range of 70% - 87% from an uncontrolled level as shown in Table 3-4.

[9] *Super DESOX®: Providing Bechmark Effectiveness for SOx Reduction*, D. Sellery, Murphy Oil Corporation and B. Riley, GRACE Davison.

[10] *The Role of Additives in Reducing Fluid Catalytic Cracking SOx and NOx Emissions*, A. Vierheilig and M. Evans, Petroleum and Coal, Volume 45, 3-4, 147-153, 2003.

TABLE 3-4
Commercial Results of SOx Reduction Additives

FCC Type **Combustion Mode**	***Kellogg*** **Total**		***UOP High Eff,*** **Total**		***UOP SBS*** **Total**		***UOP Stacked*** **Partial**
Additive	*SOXGETTER*	*DESOX*	*SOXGETTER*	*DESOX*	*SOXGETTER*	*DESOX*	*SOXGETTER*
Feed Quality							
Fresh Feed Rate, MBPD	19.1	18.5	55.5	53.6	64.0	63.0	7.0
Fresh Feed Sulfur, wt%	0.52	0.54	0.71	0.70	1.25	1.49	0.55
Operating Conditions							
Reactor Temperature, ^{o}F	1009	1009	1006	999	1005	1005	985
Reactor O_2, vol%	1.9	1.9	0.9	1.1	1.1	1.3	1.5
Additive Addition, lb/day	728	676	1583	2081	2125	3240	40
Emissions							
Uncontrolled SOx, lb/hr	1181	1086	2046	1895	3100	3853	35
Controlled SOx, lb/hr	154	141	286	303	868	1117	11
Controlled SOx, ppmv	188	179	358	370	575	754	98
Reduction %	**87**	**87**	**86**	**84**	**72**	**71**	**70**
Additive Efficiency, lb/lb at equivalent SOx red level	**34**	**34**	**27**	**18**	**25**	**20**	**15**

Reference: *The Role of Additives in Reducing Fluid Catalytic Cracking SOx and NOx Emissions,* A. Vierheilig and M. Evans, Petroleum and Coal, Volume 45, 3-4, 147-153, 2003.

SOx reducing catalysts also reduce PM10. In 2003, during the development of Rule 1105.1 – Reduction of PM10 and Ammonia Emissions from Fluid Catalytic Cracking Units, five refineries in the District experimented with SOx reducing catalysts supplied by Intercat Inc. and Grace-Davidson. Data collected from 2 refineries shown in Table 3-5 shows that with the use of SOx reducing catalysts, SOx and PM_{10} emissions could be reduced by approximately 40% - 60%. [11]

TABLE 3-5
Application of SOx Reducing Catalysts at Two Refineries in the District

Refinery	**#1**	**#1**	**#2**	**#2**
Test Date	Oct-01	Mar-02	Aug-96	Oct-01
SOx Reducing Additives (lbs/day)	0	178	0	1,471
Total PM_{10} (lbs/hr)	11.41	6.50	128.89	48.25
SOx (lbs/day)	2,291	1,352	4,553	1,583
Average Period for SOx (days)	16	23	4	24

[11] Staff Report of SCAQMD Rule 1105.1 – Reduction of PM10 and Ammonia Emissions from Fluid Catalytic Cracking Unit, October 9, 2003.

Percent Reduction	43% for $PM_{10,}$ 41% for SOx	63% for $PM_{10,}$ 65% for SOx

Note: The percent reduction in total PM10 with the SOx reducing additives for Refinery #1 was calculated as follows: % reduction = (1-(6.50/11.42))x100 = 43%. Same approach is used to estimate the percent reduction in total PM10 for Refinery # 2, and the percent reductions in SOx emissions for both refineries. SOx emissions from FCCUs are reported on a daily basis and staff has used an average period from 4 days to 24 days to estimate an average ~~of SOx~~of SOx emissions at these 2 refineries. The information here was presented in the final Staff Report of Rule 1105.1, October 2003.

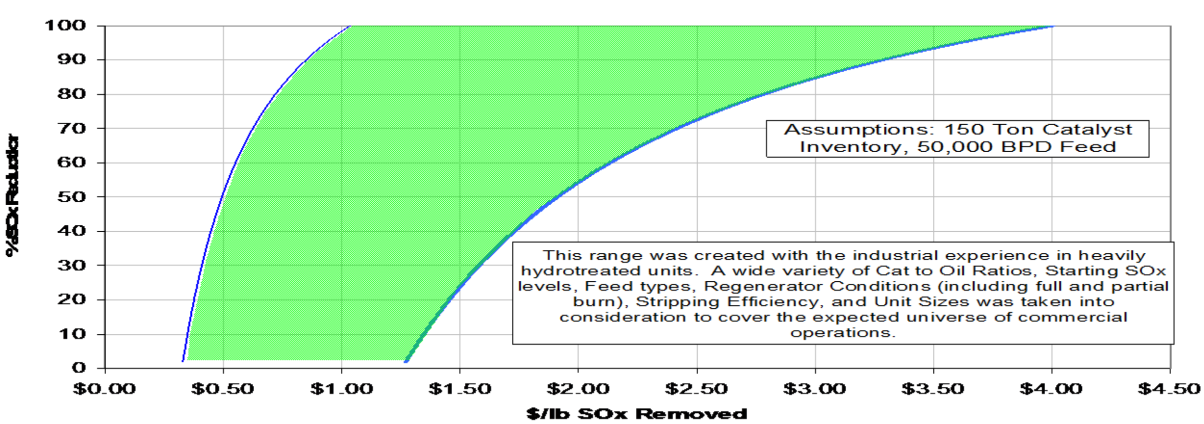
Just recently, a refinery in the District voluntarily conducted a short-term testing with SOx reducing catalysts from September 2008 – December 2008. CEMS was used to continuously measured SOx. Source tests were conducted to measure SOx and PM10. The results indicated that SOx could be reduced to 7 ppmv, 0% O2, without any increase in PM10. A considerable amount of SOx reducing additives was needed throughout this period of time. The short-term testing proceeded without any problems to the FCCU operation. Additional long term testing would be needed however to ensure that a level of 7 ppmv or below was a sustainable level with SOx reducing catalysts.

Costs and Cost Effectiveness for SOx Reducing Catalysts in Literature

Commercial data from Intercat for SOXGETTER® have shown that 85% reduction in SOx, resulting in 50 ppmv emissions, can be achieved with an addition rate of 18 lbs SOx per pound of additive. Decreasing emissions to below 25 ppmv reduced the additive efficiency to below 14 lbs SOx per pound of additive. The concentration of SOXGETTER® required to reduce emissions below 25 ppmv was slightly greater than 5% by weight of the total catalyst inventory. The relative cost increase to reduce emissions from 50 to 25 ppmv was 31%.

Figure 3-2 was built based on a manufacturer's field and laboratory experience with the additives and provided to staff during the development of Rule 1105.1. In this scenario, if 85% reduction is needed to achieve 25 ppmv SOx outlet concentration, the cost effectiveness will be approximately $6,000 per ton SOx removed. [12]

FIGURE 3-2
Efficiency of SOx Reducing Additives



[12] Staff Report of SCAQMD Rule 1105.1 – Reduction of PM10 and Ammonia Emissions from Fluid Catalytic Cracking Unit, October 9, 2003.

In other references shown in Table 3-6, a range of \$500 - \$3,000 per ton SOx reduced has been reported in literature.

Through the 2008 Survey Questionnaire, the refineries reported that they currently use Intercat SUPER SOXGETTER and Grace Davison SUPERDESOX at a rate of \$6 - \$8 per pound at an addition rate of 220 lbs/day – 800 lbs/day to the FCCUs.

TABLE 3-6
Cost Effectiveness of SOx Reducing Catalysts

SOx Level	Cost Effectiveness
7 ppmv at 0% O2 (short-term testing)	\$18,941 per ton (3)
25 ppmv at 0% O2, 365 day average and 50 ppmv at 0% O2, 7-day rolling average	\$500 - \$880 per ton (1)
50% reduction from uncontrolled level	\$2,000 - \$3,000 per ton (2)

Note: 1) *Assessment of Control Options for Petroleum Refineries in the Mid-Atlantic Region – Final Technical Support Document*. Prepared by MACTEC Federal Programs, Inc. for the Mid-Atlantic Regional Air Management Association (MARAMA), January 31, 2007. 2) *Reducing Refinery SOx Emissions*. E. Butler, K. Groves, J. Hymanyk of Chevron Canada Limited and M. Maholland, P. Clark, and G. Aru of Intercat Inc. Petroleum Technical Quarterly, Quarter 3, 2006. 3) Short-term testing with SOx reducing additives at a refinery in the District.

3.3.2 Wet Gas Scrubbers

Wet scrubbing is used to control both SOx and particulate. There are two types of wet scrubbing that are typically used for FCCUs, the caustic-based non-regenerative wet scrubbing and the regenerative scrubbing. Both systems can achieve a level of less than 5 ppmv demonstrated at several refineries in the U.S. as shown in Table 3-7.

Non-Regenerative Wet Gas Scrubbers

Non-regenerative wet scrubbing is a proven control technology for many decades and there are many manufacturers in the U.S. Typically, caustic soda (NaOH) is used as the alkaline absorbing reagent for SO2. Other alkaline reagents~~, such~~, such as soda ash and magnesium hydroxide, can also be used. The absorbents capture SO2, and convert SO2 to various types of sulfites and sulfates (NaHSO3, Na2SO3, Na2SO4). Acid mist (H2SO4) is also captured. The sulfites and sulfates are later separated in a purge treatment system and the treated water, free of suspended solids, are either discharged or recycled. One example of the caustic-based non regenerative scrubbing system is the proprietary EDV (Electro Dynamic Venturi) scrubbing system offered by BELCO Technologies Corporation, shown in Figure 3-3.[13, 14]

[13] *Evaluating Wet Scrubbers*, Edwin H. Weaver of BELCO Technologies Corporation, Petroleum Technology Quarterly, Quarter 3, 2006.

[14] *A Logical and Cost Effective Approach for Reducing Refinery FCCU Emissions.* S.T. Eagleson, G. Billemeyer, N. Confuorto, and E. H. Weaver of BELCO, and S. Singhania and N. Singhania of Singhania Technical Services Pvt., India, Presented at PETROTECH 6th International Petroleum Conference in India, January 2005.

An EDV scrubbing system consists of three main modules 1) a spray tower module, 2) a filtering module, and 3) a droplet separator module. The flue gas enters the spray tower module, which is an open tower with multiple layers of spray nozzles. The nozzles supply a high density stream of caustic water, which travels countercurrent with the gas flow, circles, encompasses, wets, and saturates the flue gas. Multiple stages of liquid/gas absorption occur in the spray tower module. SO2 and acid mist are captured and converted to sulfites and sulfates. Large particles in the flue gas are also removed by impaction with the water droplets.

The flue gas saturated with heavy water droplets continues to move up the wet scrubber to the filtering module. In here, the flue gas reaches super-saturation. Water further condenses and agglomeration of fine particles in the gas stream takes place. The size and mass of the fine particulate in the gas stream continue to increase. The flue gas, super-saturated with heavy water droplets, then enters the droplet separator module. The droplet separator module consists of a bank of parallel spin vanes. The heavy, super-saturated, water droplets impinge on the walls of these spin vanes, and are drained to the bottom of the wet scrubber. The filtering module and the droplet separator modules are important components of the wet scrubber to control fine particulate.

The spent caustic water purged from the wet scrubber is typically processed in a purge treatment shown in Figure 3-4. In the purge treatment unit, a clarifier is used to remove suspended solids which are later disposed. The effluent from the clarifier is oxidized with agitated air. Sulfites are converted to sulfates, and the chemical oxygen demand (COD) is further reduced so that the effluent can be safely discharged to the waste water system.

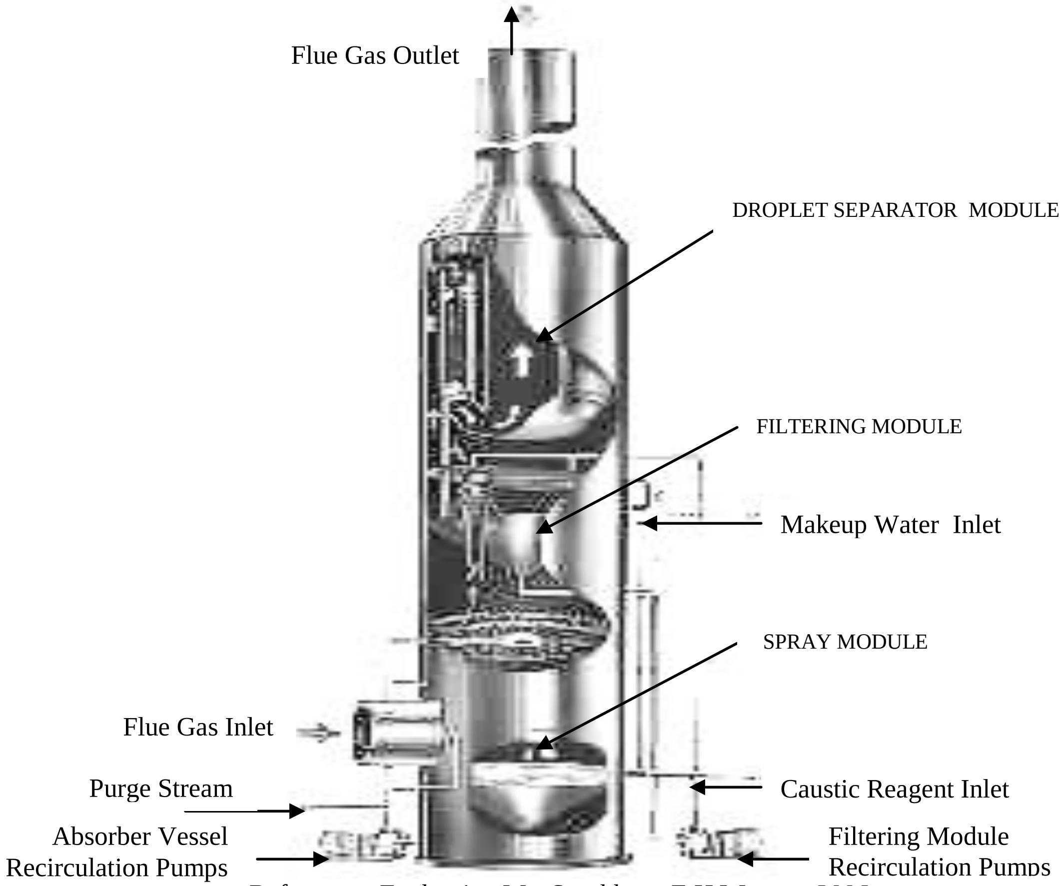
Regenerative Wet Gas Scrubbers

The regenerative wet gas scrubbing process removes the SO2 from the flue gas with a buffer that can be regenerated. The buffer is sent to a regenerative plant where the SO2 is extracted from the buffer as concentrated SO2. The concentrated SO2 is then sent to a sulfur recovery unit (SRU) to recover sulfur as byproducts, such as liquid SO2, sulfuric acid or elemental sulfur. Where the inlet concentrations of SO2 are high and a significant amount of byproducts can be generated and sold to be used in the fertilizer, chemical, pulp and paper industries, the use of regenerative wet gas scrubber is favored over non-regenerative wet gas scrubber. One example of a regenerative scrubber is the proprietary LABSORB offered by BELCO Technologies Corporation. [15, 16]

[15] *Evaluating Wet Scrubbers*, Edwin H. Weaver of BELCO Technologies Corporation, Petroleum Technology Quarterly, Quarter 3, 2006.

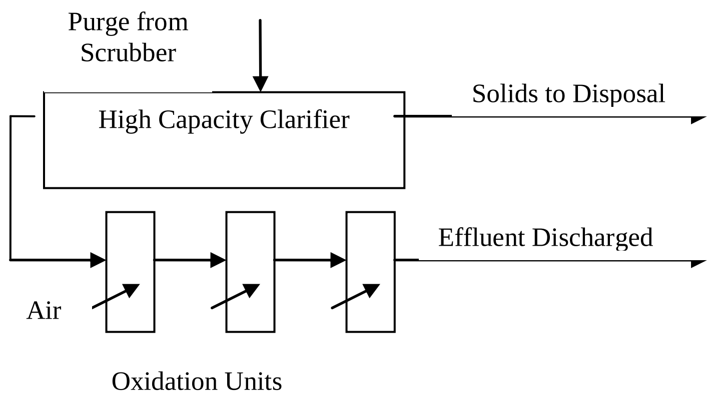
[16] *A Logical and Cost Effective Approach for Reducing Refinery FCCU Emissions.* S.T. Eagleson, G. Billemeyer, N. Confuorto, and E. H. Weaver of BELCO, and S. Singhania and N. Singhania of Singhania Technical Services Pvt., India, Presented at PETROTECH 6th International Petroleum Conference in India, January 2005.

FIGURE 3-3
EDV Non-Regenerative Wet Scrubbing System Developed By BELCO



Reference: *Evaluating Wet Scrubbers*, E.H.Weaver, 2006.

FIGURE 3-4
Purge Treatment System



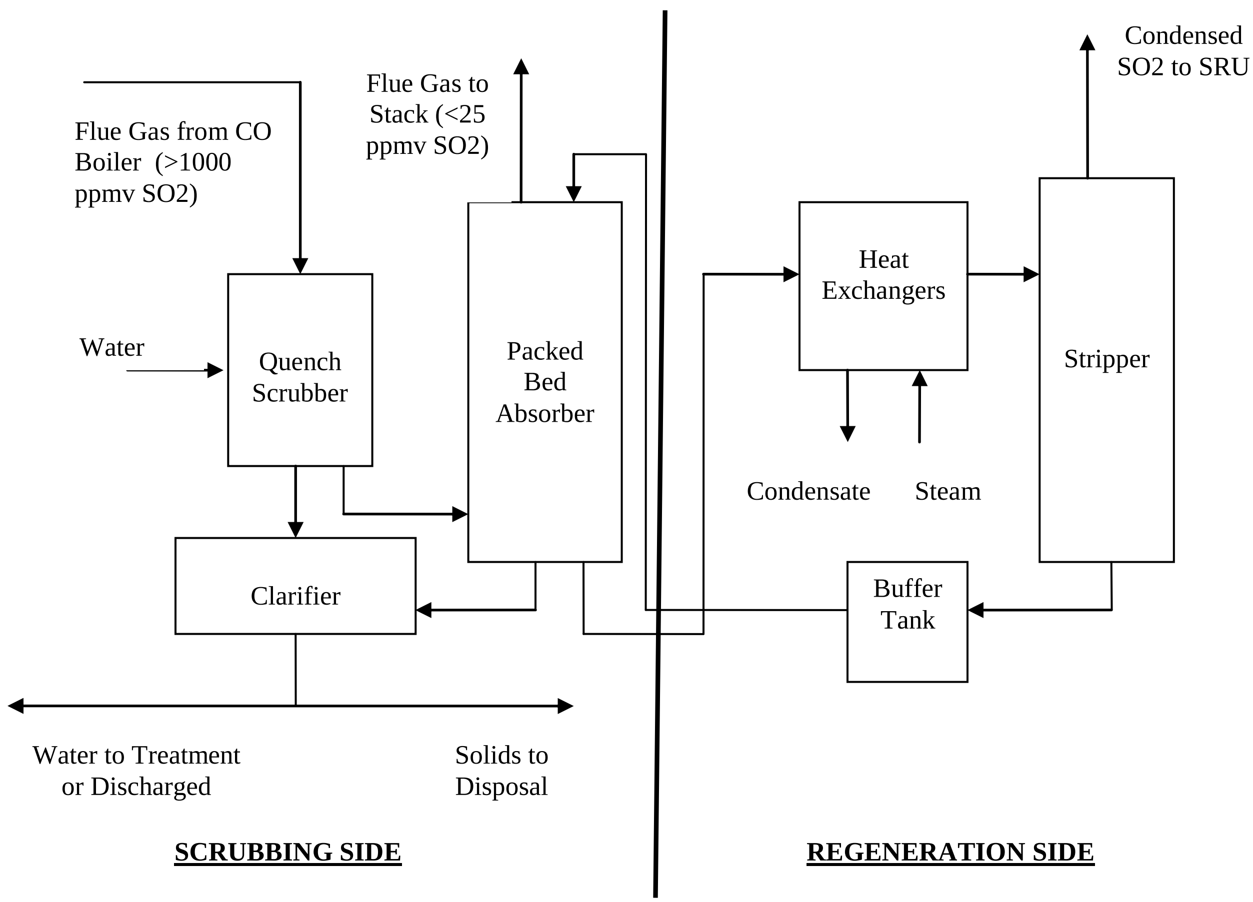
The LABSORB scrubbing process, as shown in Figure 3-5, uses a patented non-organic aqueous solution of sodium phosphate salts as a buffer. This buffer is made from two common available products, caustic and phosphoric acid. The LABSORB scrubbing system is capable of reducing

SOx to 25 ppmv or less. The LABSORP system consists of 1) a quench pre-scrubber, 2) an absorber, and 3) a regeneration section which typically includes a stripper and a heat exchanger.

In the scrubbing side of the regenerative scrubbing system, the quench pre-scrubber is used to wash out the large particles carried over, as well as acid components in the flue gas such as HF, HCl and SO3. The absorption of SO2 is carried out in the absorber. The absorber is typically a single high-efficient packed bed scrubber, packed with high-efficient structural packing materials. In some scenarios, such as when the inlet SO2 concentration is low, a multiple-staged packed bed scrubber, or a spray and plate tower scrubber, is recommended to achieve an outlet concentration of 25 ppmv or less.

In the regenerative side of the regenerative scrubbing system, the SO2-rich buffer stream is first heated by steam to vaporize the water and remove it from the buffer. The buffer stream is then sent to a stripper/condenser to separate the SO2 from the buffer. The buffer free of SO2 is returned to the buffer mixing tank while the condensed-SO2 gas stream is sent back to the SRU for further treatment.

FIGURE 3-5
LABSORB Regenerative Wet Scrubbing System Developed By BELCO



A regenerative wet gas scrubber typically costs more than a non-regenerative unit to install. BELCO Inc. estimated that the capital cost of a regenerative system is about 2.4 times the capital cost of a non-regenerative system, primarily due to the additional complexity of the regenerative wet scrubbing system. However, the regenerative system has a significant advantage in annual operating costs because the alkaline absorbing buffer in the regenerative system can be regenerated, low amount of reagents used in the regenerative system, and the byproducts (e.g. elemental sulfur) can be sold. The annual operating costs of a regenerative system are estimated to be about 35% of the annual operating costs of a non-regenerative system as shown in Table 3-7. Table 3-8 presents an estimate for cost effectiveness of the wet gas scrubber reported in literature, ranging from $500 - $3,000 per ton to achieve 25 ppmv. As shown later, a 5 ppmv and lower level has also been achieved. The consultants and staff's estimated a cost effectiveness of $12,000 - $76,000 per ton to achieve 5 ppmv level as shown in Chapter 12 of this report.

TABLE 3-7
Capital Costs and Annual Operating Costs of Regenerative Wet Gas Scrubbing System

Type of Costs	Percent Of Costs Comparing to Non-Regenerative WGS
Capital Costs:	240% of Non-Regenerative WGS's
Operating Costs:	
Caustic	18%
Power	35%
Make-Up Water	Less than 5%
Water Discharge	Less than 5%
Solids Disposal	Less than 5%
Operating & Maintenance	20%
Steam	10%
Cooling Water	Less than 5%
Phosphoric Acid	5%

Reference: *Evaluating Wet Scrubbers*, Edwin H. Weaver of BELCO Technologies Corporation, Petroleum Technology Quarterly, Quarter 3, 2006.

TABLE 3-8
Cost Effectiveness for Wet Gas Scrubbers

SOx Achieved Level	Cost Effectiveness
5 ppmv at 0% O2, 365 day average	$12,000 - $76,000 per ton (2)
25 ppmv at 0% O2, 365 day average 50 ppmv at 0% O2, 7-day rolling average	$500 - $3,000 per ton (1)

Note: 1) *Assessment of Control Options for Petroleum Refineries in the Mid-Atlantic Region – Final Technical Support Document*. Prepared by MACTEC Federal Programs, Inc. for the Mid-Atlantic Regional Air Management Association (MARAMA), January 31, 2007. 2) Refer to the consultants' report for this project. The high end $76,000 per ton was for a refinery that already has the feed extensively hydrotreated to a level slightly above 10 ppmv.

3.4 Achieved-In-Practice Information

As shown in Table 3-9, there is an extensive list of refineries in the U.S. have been installed wet gas scrubbers or use SOx reducing catalysts to meet a typical U.S. EPA current standard of 25 ppmvd SO2 at 0% O2, 365-day rolling average; 50 ppmvd at 0% O2, 7-day rolling average set through various consent decrees since 2001.

TABLE 3-9
SOx Control Technology for FCCUs

Refinery	SOx Limit	Technology	Implementation
Marathon Petroleum Co LLC., Garyville Refinery, Louisiana (1)	25 ppmvd at 0% O2, 365-day rolling average	Wet Gas Scrubber	NA
BP, Texas City, Texas (4)	25 ppmvd at 0% O2, 365-day rolling average	Wet Gas Scrubber & SOx Reducing Catalysts	2006
Valero Delaware City. FCCU w CO boiler (2), (5)	25 ppmvd at 0% O2, 365-day rolling average; 50 ppmvd at 0% O2, 7-day rolling average. Achieved 1 ppmv – 2ppmv SOx, 0% O2.	Wet Gas Scrubber BELCO & CANSOLV	By 2006
ConocoPhyllips Bayway. FCCU w two CO boilers. (2)	25 ppmvd at 0% O2, 365-day rolling average; 50 ppmvd at 0% O2, 7-day rolling average.	Wet Gas Scrubber	By 2005
ConocoPhyllips Trainer. FCCU w two CO boilers. (2)	25 ppmvd at 0% O2, 365-day rolling average; 50 ppmvd at 0% O2, 7-day rolling average.	Wet Gas Scrubber	By 2006
Motiva, Convent, LA (2)	25 ppmvd at 0% O2, 365-day rolling average (225,000 barrels per day capacity FCCU)	Wet Gas Scrubber	2006 – 2007
Motiva, Port Arthur, TX (3)	25 ppmvd at 0% O2, 365-day rolling average (235,000 barrels per day capacity FCCU)	Wet Gas Scrubber	2001
Equilon, Wilmington, CA	25 ppmvd at 0% O2, 365-day rolling average (99,000 barrels per day capacity FCCU)	SOx Reducing Catalysts	2001
Equilon, Martinez, CA (3)	25 ppmvd at 0% O2, 365-day rolling average (155,000 barrels per day capacity FCCU)	SOx Reducing Catalysts	2001
Equilon, Anacortes, WA (3)	25 ppmvd at 0% O2, 365-day rolling average (145,000 barrels per day capacity FCCU)	Wet Gas Scrubber	2006
Deer Park Refining, Deer Park, TX (3)	25 ppmvd at 0% O2, 365-day rolling average (340,000 barrels per day capacity FCCU)	Wet Gas Scrubber	2003

Note: 1) The U.S. Environmental Protection Agency RACT/BACT/LAER Clearinghouse; 2) *Assessment of Control Options for Petroleum Refineries in the Mid-Atlantic Region – Final Technical Support Document*. MACTEC Federal Programs, Inc. for Mid-Atlantic Regional Air Management Association (MARAMA), January 31, 2007; 3) *Motiva Enterprises LLC, Equilon Enterprises LLC, and Deer Park Refining Limited Partnership Civil Judicial Settlement*, March 21, 2001; 4) *BP Texas City Site – Texas City, Texas – 2004 Environmental Statement*, June 2005. 5) Valero installed two wet gas scrubbers for the FCCU and fluid coker units continuously achieved 1 ppmv – 2 ppmv SOx, at 0% O2 in the past 2 years.

An extensive study by a refinery in Canada indicates that wet gas scrubbers are commonly used to achieve an emission reduction of 95%, while reducing additives are routinely being used to achieve 85% - 90% reduction. [17] As shown in Table 3-9, it seems that SOx reducing catalysts are typically the choice for FCCUs with average capacity of less than 150,000 barrels feed per day, while wet gas scrubbers are typically the choice for FCCUs with capacity higher than 150,000 barrels per day.

Achieved-In-Practice Information for 5 PPMV Using Wet Gas Scrubbers

In the past several months, District staff contacted many air pollution control agencies throughout the nation to collect the performance information for the FCCU's wet gas scrubbers. Some air pollution control agencies do not require a facility to submit CEMS data, and in this case, the agencies provide staff with source test or RATA information.

To date, staff received the performance data of ten FCCU's wet gas scrubbers. All ten FCCU's wet gas scrubbers achieved a level below 18 ppmv. Six out of the ten FCCUs overly surpassed the performance of a typical wet gas scrubber (i.e., 25 ppmv SO2 [at] 0% O2, 365-day rolling average and 50 ppmvd at 0% O2, 7-day rolling average required by the U.S. EPA.) Staff was informed that many facilities choose not to lower the SOx level below the level required by the U.S. EPA. However, lower SOx levels are achievable by scrubbing the flue gases with more caustic solution at a higher pH level. Staff identified six facilities that opted to achieve these lower SOx levels. The resulting emissions from these six outstanding refineries are shown in Table 3-10, which demonstrate that wet gas scrubbers can achieve a level below 5 ppmv at 0% O2 in practice.

TABLE 3-10
Achieve-in-Practice Level for FCCU's Wet Gas Scrubbers

Facility	Control Equipment Manufacturer	Start-Up	SO_2	Method (CEMS or Source Test)
A Refinery in *SCAQMD* (1)	Wet gas non-regenerative scrubber/wet ESP as polisher	2008	< 5 ppmv	Source Test & CEMS (10/2008)
Valero *Delaware City, DE* (2)	BELCO/CANSOLV – regenerative packed bed scrubber	2006	1-2 ppmv	CEMS (1/2008 – 6/2009) & Source Test
Conoco Phillips *Ferndale, WA*(3)	BELCO	2002	3.87 ppmv	RATA (5/13/08)
Lion Oil *El Dorado, AR* (4)	BELCO	2002	2.65 ppmv	Source Test
Placid Refining *Port Allen, LA* (5)	BELCO	2008	< 1 ppmv	Source Test (2/19/09)
Citgo (FCCU-A) *Lake Charles, LA* (5)	BELCO	2005	1.87 ppmv	RATA (9/13 and 9/14/05)

[17] *Reducing Refinery SOx Emissions*. E. Butler, K. Groves, J. Hymanyk of Chevron Canada Limited and M. Maholland, P. Clark, and G. Aru of Intercat Inc. Petroleum Technical Quarterly, Quarter 3, 2006.

Note:
1) Source test data was conducted in October, 2008. CEMS data was submitted to SCAQMD by the refinery. Concentration was estimated by SCAQMD staff based on the average refinery gas throughputs. CEMS/source test data shown in Appendix C of this report.
2) Telephone conversations and emails between Minh Pham (SCAQMD) and Ravi Rangan of Delaware Department of Natural Resources and Environmental Control (DNREC) between April 2008 and July 2009. Permit for Delaware City Refinery (aka Premcor Refining) is now owned by Valero. Source test and CEMS data provided by DNREC. The unit includes a BELCO pre-scrubber, an amine-based regenerative CANSOLV packed-bed absorber, and a caustic polisher to reduce both SOx and particulate emissions for their FCCU and their fluidized coker unit (FCU). The system for the FCCU is to treat an inlet flow of 442,400 scfm, and 258,200 scfm for FCU. The system is to reduce 97% emissions from FCCU, and 99% emissions from FCU. The systems were in operation since 2006, and continuously achieved levels of 1 ppmv – 2 ppmv SOx, 0% O2. Extensive CEMS data were provided by air quality engineer of Delaware City. The capacity of this refinery FCCU is about twice bigger than the largest refinery FCCU in the District.
3) Telephone conversations and emails between Kevin Orellana (SCAQMD) and Toby Allen of Northwest Clean Air Agency between July and November 2009.
4) Telephone conversations and emails between Kevin Orellana (SCAQMD) and Mary Pettyjohn of Arkansas Department of Environmental Quality in August 2009.
5) Telephone conversations and emails between Kevin Orellana (SCAQMD) and Tim Bergeron of Louisiana Department of Environmental Quality between August and November 2009

3.5 Proposed BARCT Level and Emission Reductions

The consultants (ETS/AEC) recommended a BARCT level of 5 ppmv at 0% O2, 365-day average for all remaining five FCCUs based on the solid achieve-in-practice performance of a wet gas scrubber at the refinery in the District for the past 6 months. The estimated emission reductions and cost effectiveness based on ETS/AEC are shown in Table 3-11~~would be:~~

TABLE 3-11
Emission Reductions & Cost Effectiveness Estimates (ETS/AEC)

Refinery:	1	2	3	4	5	6	Total
Emissions Reduction (tpd)	0.58	0.19	0.28	0.20	0.87	0.94	3.07
~~Emissions Reduction (tpd)~~Cost Effectiveness (ETS/AEC)	$14.4k	$76.2k	$36.6k	$42.1k	$11.6k	$12.8k	~~$24.6k~~$20.8k

Since there are at least six refineries in the U.S. successfully operating wet gas scrubbers to achieve a level below 5 ppmv, staff concurred with the consultants' recommendation, and proposed to set BARCT for FCCUs at 5 ppmv, 0% O2, 365-day average. However, because Refinery 2 has heavily treated their FCCU feed to the low 10 ppmv level, installing a wet gas scrubber to get to a level of 5 ppmv is not cost effective ($76 K per ton). Therefore, staff removed the emission reductions and costs associated with this control scenario from its proposal and subsequent analyses. With this refinement, the anticipated emission reductions and weighted average cost effectiveness from this process category are estimated as ~~follows:~~shown below. Staff hired Norton Engineering Consultants (NEC) to review the cost analyses conducted by ETS/AEC. The cost effectiveness estimated by using NEC recommendations is shown in Table 13-2.

TABLE 3-12
Comparison of Cost Effectiveness
ETS/AEC versus NEC

Refinery:	1	3	4	5	6	Total
Emissions Reduction (tpd)	0.58	0.28	0.20	0.87	0.94	2.88
~~Emissions Reduction (tpd)~~Cost Effectiveness based on ETS/AEC ($/ton)	$14.4k	$36.6k	$42.1k	$11.6k	$12.8k	$19.6k
Cost Effectiveness based on input from NEC ($/ton)	$15.4k	$41.3-$44.2k (Note)	$45.1k	$11.6k	$12.8k	$21.2k

Note: The low end of the cost effectiveness reflects the costs of a WGS without additional PM10 control capability and the high end of the cost effectiveness reflects the costs of a WGS with additional PM10 control.

The proposed BARCT is then equal to approximately 3.25 lbs/thousand barrels feed, ~~80%~~77% reduction from the Tier I level of 13.7 lbs/thousand barrels feed.

Chapter 4 – Refinery Boilers and Heaters

4.1 Process Description

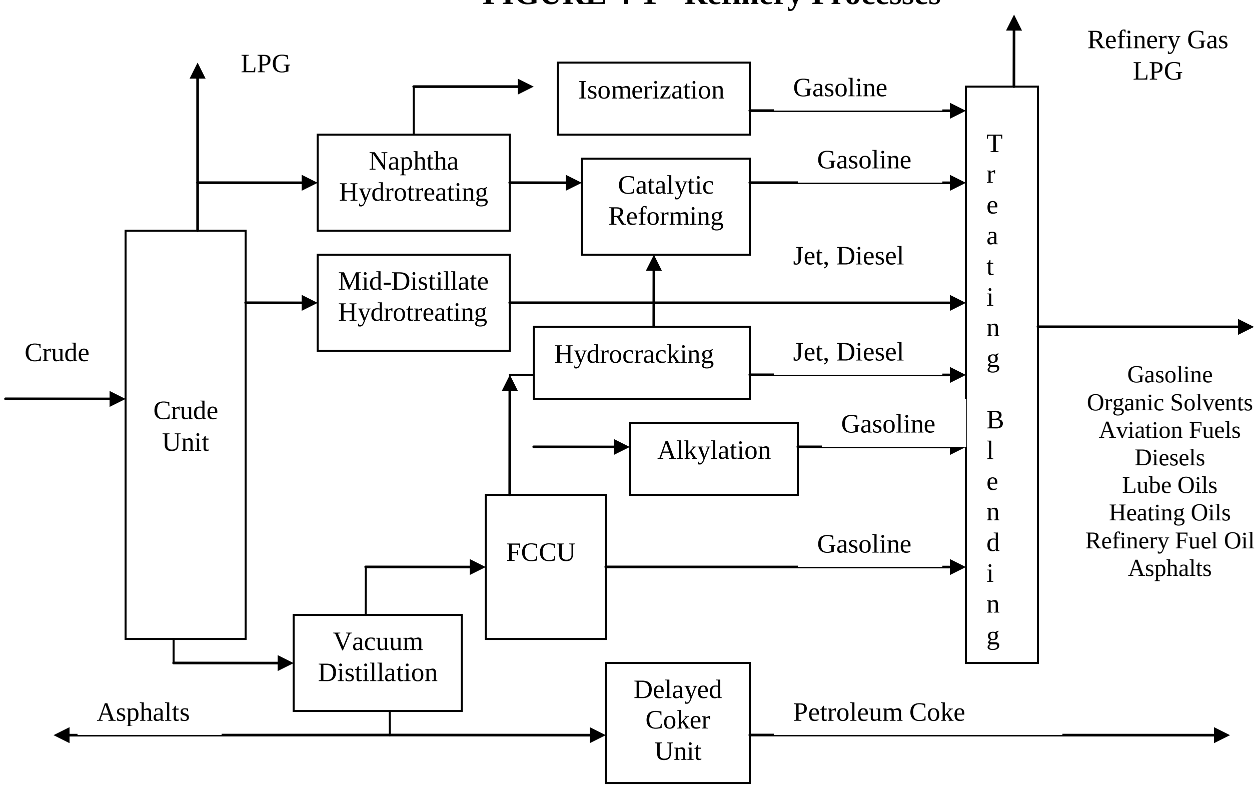
Boilers and heaters are used extensively in almost all of the processes in refinery such as distillation, hydrotreating, fluid catalytic cracking, alkylation, reforming, and delayed coking. Figure 4-1 provides a simplified diagram of the processes where boilers and heaters are used.

The refinery heaters and boilers primarily use refinery gas, one of the products generated at the refinery. As a back-up fuel, most of these boilers and heaters use natural gas. Liquid fuel or solid fuel is rarely used in refinery boilers and heaters. The combustion of sulfur or sulfur compounds in fuel generates sulfur dioxide (SO_2), with a small amount being further oxidized to sulfur trioxide (SO_3):

$$S + O_2 = SO_2$$
$$SO_2 + ½ O_2 = SO_3$$

There are approximately 300 boilers and heaters in the refineries. The majority (96%) of these boilers and heaters are classified as major SOx sources. Collectively, the boilers and heaters emit about 3 tons per day SOx, ranging from 1 lbs to 498 lbs per day from each source, with SOx outlet concentration ranging from 7 ppmv – 200 ppmv.

FIGURE 4-1 - Refinery Processes



4.2 Current Allocations and Emissions

4.2.1 Allocations

In 1993, all boilers and heaters at the refineries were provided allocations based on the highest reported fuel usage from 1987 to 1992, and an emission factor of 6.76 lbs SOx per million cubic foot of refinery fuel gas. This emission factor was developed based on an assumption that the refinery fuel gas would meet the 40 ppmv standard in Rule 431.1.

TABLE 4-1
SOx Allocations for Refinery Boilers/Heaters

Facility	Emission Factor (lbs/mmcft)	Tier I Allocations (lbs/year)	Tier I Allocations (tons/day)
A	6.76	190,422	0.26
B	6.76	139,918	0.19
C	6.76	73,779	0.10
D	6.76	101,839	0.14
E	6.76	93,315	0.13
F	6.76	49,859	0.07
		Total	**0.89**

4.2.2 Emissions

In calendar year 2005, the refineries reported a total of 3 tons per day SOx emissions from all 300 boilers and heaters currently operated at the refineries. Table 4-2 presents a list of the top 16 emitters in this category which collectively emitted about 1 ton per day of SOx in 2005.

TABLE 4-2
SOx Emissions from Top Emitting Boilers/Heaters

Facility	Device Description	Rating (mmbtu/hr)	2005 Emissions (tons/day)	2006 Emissions (tons/day)	2007 Emissions (tons/day)
B	Crude Heater	550	0.08	0.07	0.07
C	Crude Heater	350	0.10	0.11	0.17
C	Steam Reforming Heater	340	0.09	0.06	0.1
C	Steam Generation Boiler	352	0.06	0.07	0.11
C	Steam Generation Boiler	Not in operation	0.06	0.06	0.11
C	Crude Heater	154	0.04	0.04	0.07
C	Delayed Coking Unit Heater	175	0.04	0.05	0.05
C	Delayed Coking Unit Heater	175	0.04	0.07	0.06
D	Crude Heater	457	0.07	0.11	0.05
D	Hydrogen Plant Furnace	527	0.04	0.05	0.04
D	Steam Generation Boiler	291	0.03	0.02	0.02

TABLE 4-2 (Continued)
SOx Emissions from Top Emitting Boilers/Heaters

Facility	Device Description	Rating (mmbtu/hr)	2005 Emissions (tons/day)	2006 Emissions (tons/day)	2007 Emissions (tons/day)
E	Coking Unit Heater	252	0.07	0.06	0.06
E	Crude Distillation Heater	175	0.05	0.06	0.06
E	Delayed Coking Unit Heater	168	0.05	0.05	0.05
E	Auxiliary Boiler	139.5	0.04	0.06	0.04
E	Steam Generation Boiler	184	0.04	0.04	0.04
	Total 16 Heaters (1 Not in Operation)		**0.91**	**0.98**	**1.11**

Note: The 2005 SOx emissions were from SCAQMD database for the period from January 2005 – December 2005. The 2006 and 2007 emissions were reported by the facilities through a Survey Questionnaire distributed by SCAQMD in 2008.

As part of the responses to the 2008 SCAQMD Survey, the refineries reported that the refinery fuel gas is generally hydrotreated with Amine solution to reduce sulfur before being combusted in the refinery heaters and boilers. The sulfur contents in the refinery fuel gas were reported to be in a range of 49 ppmv – 327 ppmv. The SOx concentrations in in the boilers/heaters' stacks vary from 6.5 ppmv – 44 ppmv

4.3 Control Technology

Generally, SOx emissions from boilers and heaters can be further reduced by:

- Using lower sulfur fuels;
- Improving efficiency of fuel gas treating system; and
- Using dry or wet gas scrubbers.

4.3.1 Lower Sulfur Fuels

Currently, many boilers and heaters in the U.S. still use solid fuel or liquid fuel. Solid fuel and liquid fuel typically contain higher sulfur content than refinery fuel gas or natural gas, thus the combustion of solid fuel and liquid fuel generates more NOx and SOx than other types of fuel. Recently, the U.S. EPA has reached various settlement agreements with the refineries to eliminate, or minimize, the use of solid fuel/liquid fuel in all boilers and heaters operated at the refineries.[18, 19] According to these settlement agreements, the use of liquid/solid fuels is only allowed during natural gas curtailment periods.

[18] Motiva Enterprises LLC, Equilon Enterprises LLC, and Deer Park Refining Limited Partnership Civil Judicial Settlement, March 21, 2001.

[19] *BP Exploration & Oil Co., Amoco Oil Comapany, and Atlantic Richfield Company Consent Decree*, Civil No. 2:96CV095RL

In the District, boilers/heaters at the refineries typically use refinery gas as primary fuel, and natural gas as a back-up fuel. Liquid fuel, such as diesel, is typically used in internal combustion engines. Diesel fuel, if used, must contain less than 15 ppmw (0.0015%) of sulfur to comply with the South Coast AQMD Rule 431.2.[20] This requirement is applicable to all non-RECLAIM facilities, as well as RECLAIM facilities, on and after June 1, 2004; however it has not been used to adjust the RECLAIM SOx allocations provided in 1993.

However, it should be noted that the allocations provided for the combustion of diesel/liquid fuel in 1993 were approximately 0.043 tons per day, which was less than 0.5% of the total allocations provided to RECLAIM facilities at that time. In addition, the 2005 emissions from the combustion of diesel/liquid fuel in internal combustion engines are only 729 lbs per year (or 0.001 tons per day) which is only about 0.03% of the total emissions from boilers/heaters that use refinery gas. Because the allocations and the 2005 emissions from the combustion solid/liquid fuel in refineries are negligible compared to those generated from the combustion of refinery gas, staff has chosen not to focus in adjusting the allocations of RECLAIM refineries based on the fact that they are required to comply with low sulfur diesel fuel by 2004 at this time.

4.3.2 Improving Efficiency of Fuel Gas Treating System

At the refinery, refinery fuel gas is treated in various acid gas processing units such as an amine or Merox treating unit for removal of sour components (e.g. hydrogen sulfide, carbonyl sulfide, mercaptan, ammonia). Lean amine is generally used as absorbent. At the end of the process, the lean amine is regenerated to form rich amine, and H2S is evolved as acid gas which is then fed to the SRUs/tail gas treatment as discussed in Chapter 5. By improving the efficiency of the amine treating unit to recover more sulfur from the inlet acid gas stream, the sulfur content of the outlet refinery fuel gas, and subsequently the SOx emissions from boilers and heaters that use these refinery fuel gases can be reduced.

The South Coast AQMD Rule 431.1 limits the sulfur content in the refinery fuel gas to 40 ppmv sulfur.[21] This limit was already incorporated in the RECLAIM allocations and resulted in an emission factor of 6.76 lbs SOx per million cubic feet of refinery gas. However, as shown in Table 4-3, the sulfur content in refinery fuel gas may be further reduced to 25 - 35 ppmv at some refineries in the U.S. The outlet SOx concentrations from boilers/heaters may also be limited to less than 20 ppmv. The costs of modifying an acid gas processing unit may vary widely on a case-by-case basis, therefore staff has chosen not to analyze this control option at this time, and may need to discuss this control option in details with the refineries at a later date.

[20] SCAQMD Rule 431.2 – Sulfur Contents of Liquid Fuels, Amended September 15, 2000.

[21] SCAQMD Rule 431.1 – Sulfur Contents of Gaseous Fuels, Amended June 12, 1998.

TABLE 4-3
Standards for Boilers and Heaters

Company	Description of Boilers/Heaters	SOx Standard
Marathon Petroleum Co LLC., Garyville Refinery, Louisiana [(1)]	Crude heaters, 368 mmbtu/hr Hydrogen reformer heater, 1412 mmbtu/hr Platformer heaters, 474 mmbtu/hr & 542 mmbtu/hr Vacuum tower heaters, 155 mmbtu/hr Naptha hydrotreater charge heater, 75.7 mmbtu/hr Naphtha hydrotreater reboiler heater, 138 mmbtu/hr Boiler, 526 mmbtu/hr	Inlet standard: 25 ppmv as H_2S, inlet concentration of refinery fuel gas, annual average.
Arizona Clean Fuels Yuma LLC, Yuma AZ. (Facility has not yet been built.) [(1)]	Atmospheric crude charge heater, 346 mmbtu/hr Vacuum crude charge heater, 101 mmbtu/hr Hydrocracker charge heater, 70 mmbtu/hr Hydrocracker main fractionator heater, 211 mmbtu/hr Naphtha hydrotreater charge heater, 21 mmbtu/hr Catalytic reforming charge heater, 122 mmbtu/hr Catalytic reforming interheater #1, 192 mmbtu/hr Catalytic reforming interheater #2, 129 mmbtu/hr Catalytic reforming debutanizer reboiler, 23 mmbtu/hr Distillate hydrotreater charge heater, 25 mmbtu/hr Distillate hydrotreater splitter reboiler, 117 mmbtu/hr Butane dehydrogenation reactor heater, 311 mmbtu/hr Butane conversion isostripper reboiler, 222 mmbtu/hr Delayed coking charge heaters, 99 mmbtu/hr	Inlet standard: 35 ppmv, as H_2S, inlet concentration of refinery fuel gas.

Note: 1) The U.S. Environmental Protection Agency RACT/BACT/LAER Clearinghouse.

4.3.3 Flue Gas Scrubbers

While the first two control options are aiming at reducing the sulfur content of fuel before it is combusted, flue gas scrubbing is aiming at reducing SOx emissions in the flue gas after it exits the boilers and heaters. Literature contains extensive information about these technologies. [22, 23]

[22] *Assessment of Control Options for Petroleum Refineries in the Mid-Atlantic Region – Final Technical Support Document*. Prepared by MACTEC Federal Programs, Inc. for the Mid-Atlantic Regional Air Management Association (MARAMA), January 31, 2007.

[23] Assessment of Control Technology Options for BART-Eligible Sources – Steam Electric Boilers, Industrial Boilers, Cement Plants, and Paper and Pulp Facilities. Northeast States for Coordinated Air Use Management (NESCAUM) in partnership with the Mid-Atlantic Northeast Visibility Union (MANE-VU), March 2005.

4.3.3.1 Dry Scrubbers

Dry scrubbers include 1) spray dryer scrubbers and 2) dry injection scrubbers. In dry scrubbers, a dry calcium and sodium based alkaline powered sorbent is used to absorb SO_2. A spray dryer scrubber refers to a configuration where the reaction between SO_2 and the dry sorbent takes place in a dedicated reactor (or scrubber), whereas in the dry injection scrubber, the sorbent is injected directly into the existing boiler/heater or the ducting system of the boiler/heater.

In the dry scrubbers, high temperatures (1800 – 2000 degree F) are needed to decompose the sorbent into porous solids with high adsorbing surface area. Several injection ports may be required for even distribution of dry sorbent in the boilers/heaters or ductwork. Cyclones and ESPs are typically used downstream of a dry scrubber to remove the particulate formed in the process. Dry injection scrubbers can achieve about 50% - 80% removal efficiency, whereas spray dryer scrubbers can achieve about 80% – 90%. Dry scrubbers are mostly applicable to small and medium size boilers/heaters with low level of inlet SOx.

4.3.3.2 Wet Scrubbers

In wet scrubbers, aqueous slurry of limestone, lime, or other proprietary sorbent is used to absorb SO_2. A wet scrubber includes a spray tower which is generally followed by a mist eliminator. The flue gas enters a spray tower, where it is impacted with aqueous lime or limestone slurry for SO_2 absorption. Particulate formed in the spray tower falls to the bottom of the spray tower, where it is collected and recycled back to the scrubber system or disposed. The scrubbed flue gas is then sent to a mist-eliminator to remove any entrained particulate droplets. Wet scrubbers are about 90% - 98% efficiency in removing SOx depending on the type of sorbent used.

As discussed in Chapter 3, Section 3.3.2, wet scrubbers are used extensively to control SOx and PM from FCCUs at several refineries in the U.S. A wet scrubber designed by BELCO includes a spray module with two additional modules, a filtering module and a droplet separator module, to remove fine particulate. This scrubber has been used to achieve an outlet concentration of 25 ppmv of SOx from FCCUs. Boilers/heaters are expected to achieve a level of 20 ppmv or lower as shown in Table 4-3.

4.3.3.3 Costs and Cost Effectiveness

Cost effectiveness for wet gas scrubbers has been estimated to be \$7,700 - \$45,400 per ton depending on the size of the scrubbers, inlet SOx, and amount of emissions reduced. [24] Using a wet gas scrubber may allow the refinery to combust higher sulfur fuel; and since higher sulfur

[24] *Assessment of Control Options for Petroleum Refineries in the Mid-Atlantic Region – Final Technical Support Document*. Prepared by MACTEC Federal Programs, Inc. for the Mid-Atlantic Regional Air Management Association (MARAMA), January 2007.

fuel costs less than low sulfur fuel, this can result in a savings in annual operating costs. BELCO estimated that using an EDV® wet gas scrubber with caustic soda (NaOH) as a scrubbing agent for a 198 mmbtu/hr vacuum distillation process heater burning high sulfur fuel of 150 ppmv – 200 ppmv could generate a saving of $1 - $2.8 million dollars per year.[25]

TABLE 4-4
Cost Effectiveness for Wet Scrubbers

Efficiency	Cost Effectiveness
90-99.9%	$7,700 - $45,400 per ton
99%+	$1 - $2.8 million dollars annual savings for a 198 mmbtu/hr heater

4.4 Proposed BARCT Level and Emission Reductions

For refinery boilers/heaters, the consultants studied the technologies for pre-treatment of fuel gas prior to combustion, as well as the technologies for post-treatment of flue gas after combustion. Regarding the pre-treatment of fuel gas prior to combustion, the consultants recommended that the Tier I BARCT of 40 ppmv total sulfur in refinery fuel gas be retained as BARCT. Regarding the post-treatment of flue gas from boilers/heaters after combustion, the consultants found that the wet gas scrubbers were not cost-effective. Nonetheless, the consultants found that the fuel gas at some refineries can be further reduced to the Tier I BARCT which results in about 0.89 tons per day emission reductions from the 2005 baseline. Staff concurred with the consultants' recommendation on keeping BARCT at 40 ppmv.

[25] *Controlling Fired Process Heater Emissions to Reduce Fuel Costs and Improve Air Quality,* S.T. Eagleson and N. Confuorto of BELCO, S.Singhania and N. Singhania of Singhania Technical Services Pvt., and R. John of Lisha Engineering Co., Presented in the Petrotech 7th International Oil & Gas Conference, January 24, 2007

Chapter 5 – Sulfur Recovery – Tail Gas Units

5.1 Process Description

A typical sulfur recovery system at the refineries include a sulfur recovery unit (Claus unit) followed by a tail gas treatment unit (e.g. Amine treating) to maximize the removal of H_2S.

The Claus sulfur recovery unit, as shown in Figure 5-1, consists of a reactor, converters and condensers. The two reactions proceed in the Claus sulfur recovery unit are exothermic. The first reaction occurs in the Claus reactor, where a portion of H_2S reacts with air to form SO_2.

$$2H_2S + 2O_2 \rightarrow SO_2 + S + 2H_20$$

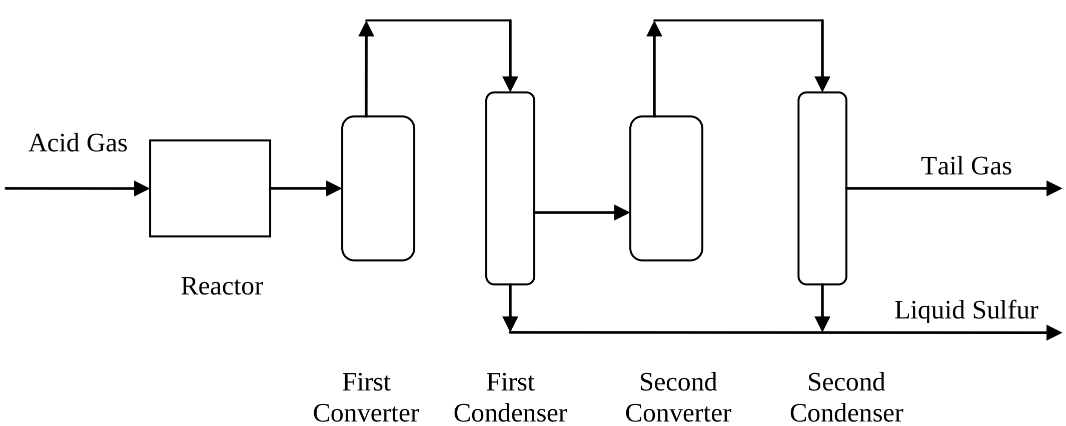
The second reaction takes place in the catalytic converter where SO_2 reacts with H_2S to form liquid elemental sulfur.

$$2H_2S + SO_2 \rightarrow 3S + 2H_20$$

Side reactions also occur which produce carbonyl sulfide (COS) and carbon disulfide (CS_2), which have presented problems in many Claus plant operations due to the fact that they cannot be easily converted to elemental sulfur and carbon dioxide,

Liquid sulfur is recovered after the final condenser. Two converters and two condensers in series generally remove 95% of the sulfur in the incoming acid gas. Some of the newer sulfur recovery units have three to four sets of converters and condensers.

FIGURE 5-1
Two Stage Claus Sulfur Recovery Process



To recover the remaining sulfur compounds in the tail gas, the tail gas is sent to a tail gas treatment process, such as amine, diethanol amine (DEA), SCOT, Wellman-Lord, and FLEXSORB.

Figure 5-2 shows a simplified diagram of SCOT tail gas treatment process. The sulfur compounds in the tail gas are reduced in a catalytic reactor to H_2S. The H_2S is absorbed in the amine (or other absorbent) in the H_2S absorber, steam-stripped from the absorbent solution in the H_2S stripper, concentrated, and recycled back to the front end of the sulfur recovery unit This approach typically increases the overall sulfur recovery efficiency of the Claus unit to 99.8% or higher. However, the fresh acid gas feed rate to the sulfur recovery unit is reduced by the amount of recycled stream, which reduces the capacity of the sulfur recovery unit. The residual H_2S in the treated gas from the absorber is typically vented to a thermal oxidizer where it is oxidized to SO_2 before emitting to the atmosphere.

FIGURE 5-2
Tail Gas Treatment – SCOT Process

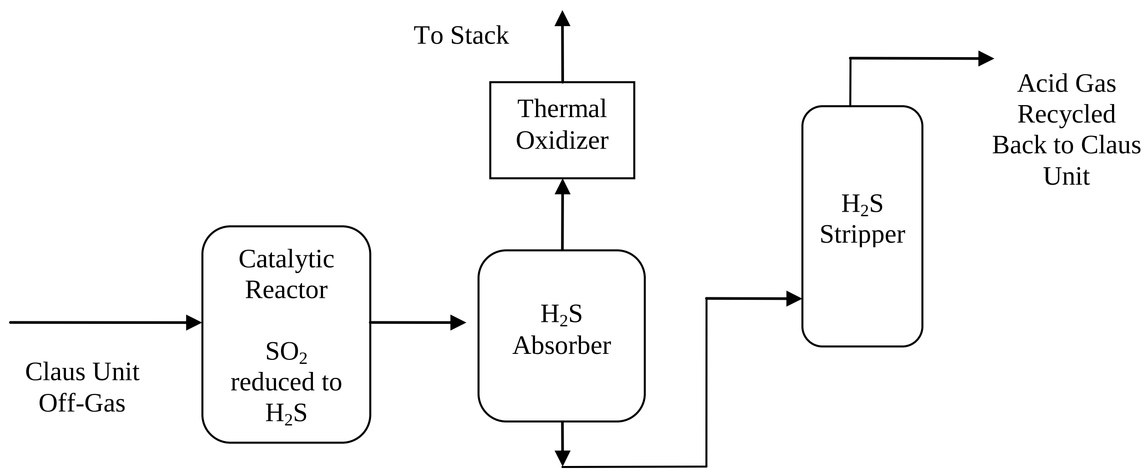
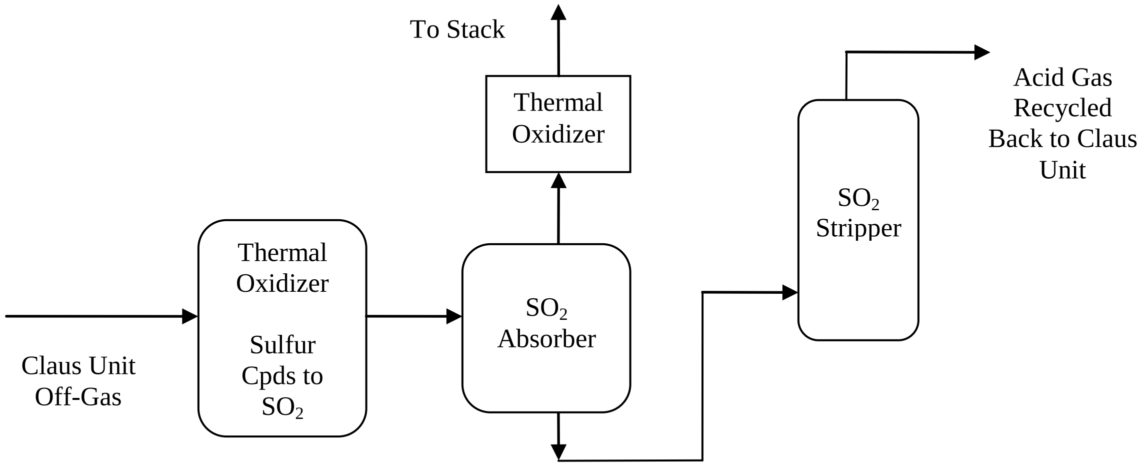


Figure 5-3 shows a simplified diagram of Wellman-Lord tail gas treatment process. The sulfur compounds in the tail gas are first incinerated with air to oxidize to SO_2. After the incinerator, the tail gas enters a SO_2 absorber, where the SO_2 is absorbed in typically sodium sulfite (Na_2SO_3) solution to form sodium bisulfite ($NaHSO_3$) and sodium pyrosulfate ($Na_2S_2O_5$). The absorbent rich in SO_2 is then stripped, and the SO_2 is recycled back to the Claus gas. The residual sulfur compounds in the treated tail gas from the SO_2 absorber is typically vented to a thermal oxidizer where it is oxidized to SO_2 before emitting to the atmosphere.

FIGURE 5-3
Tail Gas Treatment - Wellman-Lord Process



5.2 Current Allocations and Emissions

5.2.1 Allocations

In 1993, the facilities were issued emission allocations for their sulfur recovery - tail gas treatment unit based on the highest reported emissions from 1988 – 1992. The emissions allocated to each unit are listed in Table 5-1. The total Tier I allocations provided were 1.61 tons per day.

TABLE 5-1
SOx Allocations for Sulfur Recovery -Tail Gas Treatment Units

Facility	Process	Peak Year	Tier I Allocations (lbs/year)	Tier I Allocations (tons/day)
B	Tail Gas Unit	1990	353,992	0.48
A	Inorganic Chemicals	1992	280,670	0.38
A	Sour Water Oxidizer	1992	2,328	0.00
A	Sulfur Plant	1992	65,341	0.09
A	Tail Gas Unit	1992	31,343	0.04
D	KCR Process	1992	6,904	0.01
D	Merox Process	1992	1,599	0.00

TABLE 5-1 (Continued)
SOx Allocations for Sulfur Recovery -Tail Gas Treatment Units

Facility	Process	Peak Year	Tier I Allocations (lbs/year)	Tier I Allocations (tons/day)
D	Tail Gas Unit	1992	6,008	0.01
D	Tail Gas Unit	1992	50,587	0.07
G	Tail Gas Unit	1991	14,934	0.02
CC	Sour Water Coker	1988	12,360	0.02
CC	Sour Water Oxidizer	1988	12,360	0.02
CC	Sulfur Plant	1988	87,477	0.12
C	Tail Gas Unit	1988	6,500	0.01
E	Mericher Alkyd Feed	1991	250,983	0.34
			Total	**1.61**

5.2.2 Emissions

Since sulfur recovery - tail gas treatment unit with thermal oxidizers are classified as major sources in RECLAIM, the SOx emissions from these units are monitored with CEMS and reported on a daily basis to the District. The total annual emissions for 2005, 2006, and 2007, 0.96 tpd, 1.02 tpd and 0.96 tpd respectively from these units are presented in Table 5-2.

The sulfur recovery - tail gas treatment units at RECLAIM facilities are not subject to any specific concentration or emission rate standards. RECLAIM facilities are given the flexibilities to operate their equipment anyway they want provided that the total emissions from the facility are below facility emission caps. The allocations provided to these units since 1993 have not been adjusted even though there may have emerging technologies that can be used to further reduce SOx emissions from these units. Comparing the allocations provided in 1993 at 1.61 tons per day with the 2005 reported emissions at 0.96 tons per day, it seems that the sulfur recovery - tail gas treatment units at RECLAIM facilities have been slightly improved since 1993 provided that their capacity has not been changed.

Through the 2008 Survey, the refineries reported that their SRUs' capacity ranges from 90 long tons per day – 270 long tons per day. The refineries have been using more than one Claus units with the technologies such as SUPERCLAUS, FLEXSORB, or WELLMAN LORD to recover approximately 95% - 99.99% sulfur in their SRUs and tail gas treatment. All six refineries have thermal oxidizers at the end of their tail gas treatment units. A refinery reported that they would only vent the tail gas to incinerators when needed to meet the requirement of NSPS 40 CFR Part 60, Subpart J. The stack average SOx concentrations at the outlet of the thermal oxidizers vary widely from 20 ppmv at 0% O2 for Refinery E, 26 ppmv for Refinery D, 59 ppmv – 77 ppmv for Refinery A, 98 ppmv – 150 ppmv for Refinery B, and 98 ppmv for Refinery F

TABLE 5-2
SOx Emissions from Sulfur Recovery – Tail Gas Treatment Units

Facility	Device Description	Rating (mmbtu/hr)	2005 Emissions (tons/day)	2006 Emissions (tons/day)	2007 Emissions (tons/day)
B	Thermal oxidizer #2	44.5	0.16	0.22	0.26
B	Thermal oxidizer #1	39.5	0.15	0.12	0.11
A	Thermal oxidizer #70	58	0.10	0.14	0.12
A	Thermal oxidizer #20	30	0.09	0.09	0.08
A	Thermal oxidizer #10	30	0.06	0.08	0.06
C	Tail gas incinerator #1	19.5	0.01	0.00	0.01
C	Tail gas incinerator #2	19.5	0.01	0.02	0.01
CC	Thermal incinerator	NA	0.05	0.10	0.09
CC	Thermal incinerator	NA	0.02	0.01	0.02
D	Tail gas oxidizer	100	0.15	0.21	0.17
E	Incinerator for SRU	52	0.05	NA	NA
E	Incinerator for SRU	45	0.02	NA	NA
F	Thermal oxidizer	35.8	0.16	0.03	0.03
			1.03	**1.02**	**0.96**

Note: The 2005 SOx emissions were from SCAQMD database for the period from January 2005 – December 2005. The 2006 and 2007 emissions were reported by the facilities through a Survey Questionnaire distributed by SCAQMD in 2008.

5.3 Control Technology

The main purpose of the Claus sulfur recovery - tail gas treatment units is to recover sulfur. Afterwards, the treated gas is vented to a thermal oxidizer to oxidize the remaining H_2S. The Claus sulfur recovery, tail gas treatment and thermal oxidizer systems in the District generally have recovery efficiency of about 95% - 99.99% to meet NSPS 40 CFR Part 60, Subpart J limit and SCAQMD Rule 468 limit (e.g. 250 ppmv SO_2 with the use of thermal oxidizers, or 10 ppmv H_2S without the use of thermal oxidizers). The three main strategies that can be employed to further reduce SO_2 emissions from these units are 1) to increase the efficiency of the sulfur recovery unit, 2) to improve the efficiency of the tail gas treatment processes, and 3) to use a wet gas scrubber as an alternative for the thermal oxidizer.

5.3.1 Increase Efficiency of the Sulfur Recovery Unit

5.3.1.1 SELECTOX

The SELECTOX catalyst is used in the first stage of the Claus unit to promote the oxidation of H_2S to SO_2 without the use of a flame. SELECTOX catalyst has helped to increase the efficiency of sulfur recovery unit from 90% to 97%. SELECTOX has been used in San Joaquin

Refinery located in Bakersfield, California. [26] Other catalysts such as Criterion catalysts have been used to increase the sulfur recovery efficiency from a typical 96% - 97% to 99.8% - 99.9%. Testing on the tail gas unit at the Motiva Enterprises' Port Arthur refinery demonstrated that the stack SO_2 remained in the 22 ppmv – 28 ppmv range, which was only about 10% of the permitted maximum 250 ppmv required by NSPS, 40 CFR Part J. [27]

5.3.1.2 SUPER-CLAUS®

The SUPERCLAUS sulfur recovery unit is similar to the Claus unit but contains three to four catalytic converters. The first two or three catalytic converters use the Claus catalysts, while the last reactor uses a selective oxidation catalyst that highly selective and oxidize H_2S to sulfur. The efficiency of sulfur recovery is about 99%.

5.3.2 Increase Efficiency of Tail Gas Unit

5.3.2.1 SCOT Tail Gas Unit

SCOT stands for Shell Claus Off-gas Treating, which is the most common tail gas treatment system. Tail gas from the Claus unit is contacted with hydrogen and reduced in the hydrotreating reactor to form H_2S and water in the presence of a cobalt/molybdenum or alumina catalyst. The gas is then cooled and enters an amine absorber where it is contacted with monoethanolamine (MEA) or diethanolamine (DEA), or triethanolamine (TEA) to generate a rich amine stream. The rich amine stream is then desorbed in a stripper, where a lean amine stream is regenerated and recycled to the absorber, while and H_2S gas stream is sent back to the Claus unit. This technology has been used by several refineries in the District as reported through the 2008 Survey.

5.3.2.2 Sulfreen Tail Gas Unit

The Sulfreen process is a catalytic tail gas process that adds two or three Sulfreen reactors to treat the tail gas. Alumina catalyst is used to remove additional sulfur. Activated titanium oxide is used to remove COS and CS_2. Any remaining H_2S leaves the reactors are oxidized in the final stage. The recovering efficiency of the Sulfreen process is 99 – 99.9%.

5.3.2.3 Beaven Process

The Beaven process uses quinine solution to absorb H_2S in the tail gas. The absorbed H_2S is then oxidized to form a mixture of elemental sulfur and hydroquinone. Hydroquinone is

[26] *Sulfur Technology, Capability and Experience.* WorleyParsons.

[27] *Catalysts for Lower Temperature Tail Gas Unit Operation.* S. Massie and C. Wilson of Criterion Catalysts & Technologies, presented at the Brimstone Sulfur Recovery Symposium, Vail, Colorado, September 2005.

converted back to quinone. Before entering the absorber, COS and CS_2 in the tail gas can also be eliminated by the use of cobalt molybdate catalyst in a reactor located prior to the absorber. The recovering efficiency of the Beaven process is 99% – 99.9%.

5.3.2.4 Stretford Process

The Stretford process uses a hydrotreating reactor to convert SO_2 in the tail gas to H_2S, and then contacts H_2S with Stretford solution in a liquid-gas absorber. The Stretford solution contains a mixture of vanadium salt, anthraquinone disulfonic acid (ADA), sodium carbonate, and sodium hydroxide. The vanadium salt acts as a catalyst to convert H_2S into elemental sulfur. The recovering efficiency of the Stretford process is about 99%.

5.3.2.5 FLEXSORB ®

The FLEXSORB process were developed by the ExxonMobil Research and Engineering as alternative to the MDEA amine treatment process. The process uses a number of FLEXSORB solvents include the SE, SE Plus, SE hybrid, and the PS solvents. The solvents are designed to selectively absorb and convert H_2S, organic sulfur to elemental sulfur. The efficiency of FLEXSORB is about 99.9+%. This technology has been used by one refinery in the District as reported through the 2008 SCAQMD Survey.

5.3.2.6 PRO-Claus

The Parsons RedOx Claus (PROClaus) unit is a dry catalytic process that contains three additional stages, a reduction and two oxidation stages. In a reduction stage, a highly selective SO2 reduction catalyst developed by Lawrence Berkeley National Laboratory is used to accelerate the reduction of SO_2 to elemental sulfur. After this stage, the remaining H_2S is oxidized to form elemental sulfur under the presence of a Parsons Hi-Activity selective oxidation catalyst, and then it is sent to a thermal oxidizer to complete the oxidation process. An overall sulfur recovery efficiency of all three stages is 99.5%.

5.3.2.7 LO-CAT

LO-CAT is a liquid redox tail gas treatment capable of recovering 99.9+% with or with the use of a proprietary Mobile Bed Absorber (MBA) where H_2S and SO_2 are absorbed into a circulating solution and converted to elemental sulfur in the presence of a chelated-iron catalyst. The solution leaving the MBA is then oxidized. Exhaust gas from the MBA is vented to the atmosphere and contains less than 10 ppmv H_2S.

Table 5-3 provides a summary of the processes described above.

TABLE 5-3
Control Efficiency of Sulfur Recovery – Tail Gas Treatment Process

Process	Efficiency
Typical Claus with tail gas treatment and incinerators	90% - 95% (<250 ppmv)
Selectox catalyst for Claus Unit	97%
SUPERCLAUS® for Claus Unit	99%
SCOT for Tail Gas Treatment	99%
Sulfreen for Tail Gas Treatment	99% - 99.9+%
Beaven for Tail Gas Treatment	99% - 99.9+%
Stretford Tail Gas Treatment	99%
FLEXSORB Tail Gas Treatment	99.9+%
PRO-Claus Tail Gas Treatment	99.5%
LO-CAT Tail Gas Treatment	99.9+%

Reference: *Assessment of Control Options for Petroleum Refineries in the Mid-Atlantic Region – Final Technical Support Document*. Prepared by MACTEC Federal Programs, Inc. for the Mid-Atlantic Regional Air Management Association (MARAMA), January 31, 2007.

5.3.3 Wet Gas Scrubber

As described above, typically in the District, the tail gas from the Claus sulfur recovery unit is sent to an amine treatment process, which absorbs H_2S, produces a concentrated H_2S stream, and recycles the concentrated H_2S stream to the front end of the SRU. The residual H_2S in the treated gas is typically vented to a thermal oxidizer where H2S is oxidized to SO_2 before emitting to the atmosphere. This approach typically increases the overall sulfur recovery efficiency of the Claus sulfur recovery unit; however has the tendency to reduce the amount of fresh acid gas stream that could potentially be treated by the Claus sulfur recovery unit.

As an alternative to this process, the tail gas from the Claus unit is first oxidized to SO_2. The SO_2 is then captured by alkaline agent (e.g. sodium hydroxide caustic solution) in a wet gas scrubber, and the residual SO_2 not captured in the scrubber is discharged to the atmosphere. With this approach, there is no concentrated H_2S stream recycles to the front end of the SRU, and the overall sulfur recovery/removal efficiency is increased to 99.95%, above the efficiency of the current Claus SRU-Tail Gas Treatment systems in the District. [28] Two types of wet gas scrubbers that have been installed and used by the refineries in the U.S. are described in details below.

[28] *Improving Sulfur Recovery Units*, E. Juno of Sinclair Oil Corporation, S.F. Myer and C. Kulczycki of MECS, and N. Watts of CEntry Constructors and Engineers, Petroleum Technical Quarterly, Quarter 3 of 2006.

5.3.3.1 DynaWave Non-Regenerative Scrubber

Wet gas scrubbing technique is currently used at two refineries in Wyoming, the Sinclair Oil refinery, rated 72,000 barrels per day, and the Casper refinery, rated at 22,500 barrels per day. The scrubbers used at these two refineries are manufactured by DynaWave and use caustic (NaOH) as a scrubbing agent.

DynaWave scrubber can utilize other sodium based agents such as soda ash (Na_2CO_3), or calcium based agents such as lime (CaO) or limestone ($CaCO_3$), however Sinclair Oil refinery and Casper refinery have selected caustic (NaOH) because:

- Caustic was available as a 50% solution which could be pumped directly to the scrubber without further dilution or mixing. Soda ash or calcium based agents are only readily available as a powder and they would require an installation of a reagent preparation station.

- The reaction between SO_2 and caustic (NaOH) are relatively fast compared to the reaction of SO_2 with calcium based reagents. The products, sodium sulfite ($NaHSO_3$) or sodium bisulfite salts (Na_2SO_3) accumulated in the waste water stream, are soluble and can be further oxidized to reduce the COD in the waste stream to the level acceptable to the municipal wastewater treatment plant. In contrast, the products calcium sulfite ($CaSO_3$) or calcium sulfate ($CaSO_4$, aka gypsum) of the reaction between SO_2 and calcium based agents are insoluble salts which are not easily removed from the scrubber solution.

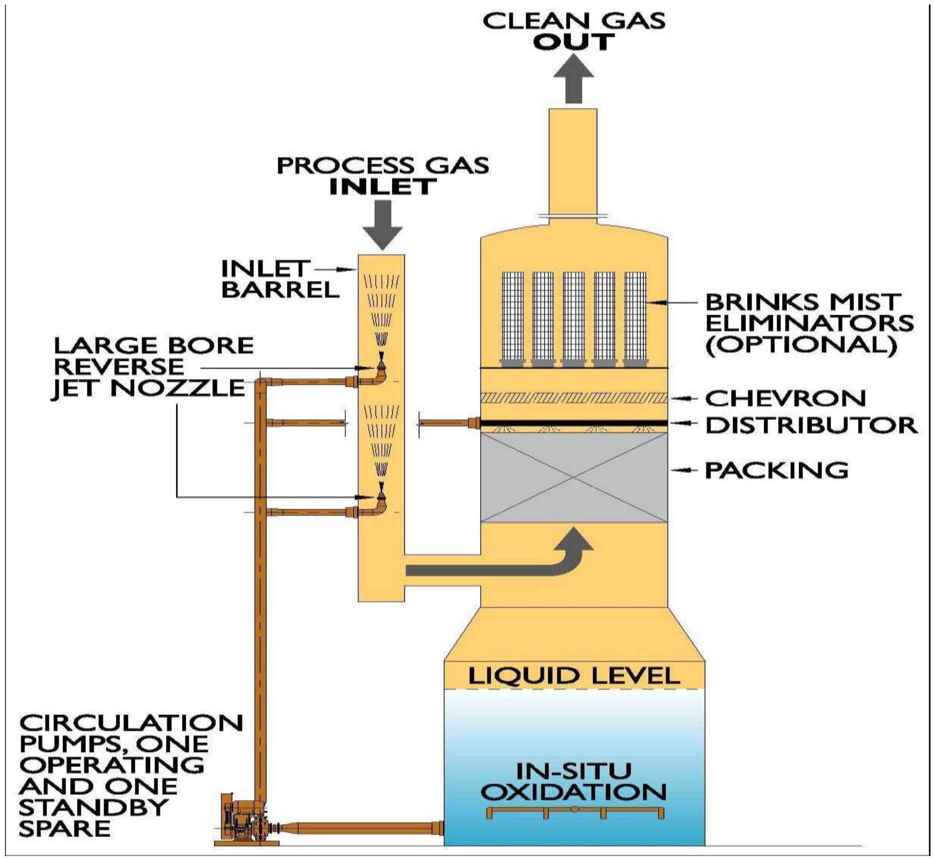
Using caustic solution as a scrubbing agent has helped the refineries to save on capital costs and annual operating costs, and improve the removal efficiency and operability of the system.

Most DynaWave scrubbers contain two stages of scrubbing, or froth zones, in the inlet barrel, as shown in Figure 5-4. In the first scrubbing stage, the inlet process gas is adiabatically saturated or "quenched". The gas exits the first scrubbing stage at 150 – 180 degree F and passes through the second scrubbing stage. In the second stage, caustic liquid agent is again injected upward into the incoming gas. The SO2 is absorbed, and reacts with the caustic agent, forming sodium by products, sodium sulfite and sodium bisulfite salts.

The reverse jet nozzles, located in the inlet barrel and used to inject the caustic reagent, is a proprietary piece of equipment supplied by Monsanto Enviro-Chem System (MECS) which is very critical to the scrubber application. A relatively large volume of scrubbing liquid is injected counter to the gas flow to create a froth zone. The gas collides with the liquid, forcing the liquid toward the wall. A standing wave, created at the point the liquid is reversed by the gas, is an extremely turbulent region. In this turbulent region, the gas absorption and particulate collection is enhanced significantly.

If the SO_2 concentration in the inlet gas stream is high, Dynaware will include a third stage scrubbing consisting of 2-inch diameter metal packing rings added to further increase the gas/liquid absorption. The liquid agent circulated to the third stage scrubbing can be turned off when it is not needed.

FIGURE 5-4
DynaWave Wet Gas Scrubber Used for Sulfur Recovery Tail Gas Treatment Unit



After passing through the third scrubbing stage, the air stream will pass through a set of chevrons which are used to maximize the liquid droplet removal. Liquid droplets disengage from the gas stream and accumulate in the bottom of the vessel. The bottom of the vessel is also used as a reservoir for the scrubber solution which ensures continuous feed to the recirculation pumps. Sulfite salts are also oxidized to sulfates in the reservoir. In addition to DynaWave scrubber, particulate filters, ESPs, or mist eliminators can be used downstream of the wet scrubber to remove fine particulates.

5.3.3.2 Cansolv® Regenerative Scrubber

Development of the Cansolv technology started in 1988 and begun by Union Carbide Canada Ltd.. Since then, it has been used commercially to control SO2 from sulfur recovery units, sulfuric acid plants, cogeneration units, and power plant boilers. In California, the Cansolv technology has also been used to control SOx emitted from a sulfuric acid plant at an oil refinery since September 2002. The Cansolv scrubber also has been installed and operated since July 2006 to control SOx from a sulfur recovery - tail gas application at BP Cherry Point refinery. The project was developed by Marsulex Inc. and is subject to an annual mass limit of 135 tons per year which can be translated to 150 ppmv SOx.[29] Cansolv advertises that their regenerative scrubber can be designed to achieve 10 ppmv SO2. [30, 31, 32]

5.4 Performance Information

The existing performance levels of the sulfur recovery units in the District reported by the facilities through the 2008 Survey are listed in Table 5-4. The SOx concentrations at the stack of the thermal oxidizers vary widely from 17 ppmv – 150 ppmv.

TABLE 5-4
Performance of SRU-Tail Gas Treatment in SCAQMD

Facility	% Sulfur Recovery	SOx Level
A	99.9%-99.99%	59 ppmv – 77 ppmv from thermal oxidizer
B	90%	98 ppmv – 150 ppmv from thermal oxidizer
C	---	17 ppmv – 56 ppmv from thermal oxidizer
D	99.9%	26 ppmv from thermal oxidizer
E	96%	20 ppmv from thermal oxidizer
F	99.5%	98 ppmv from thermal oxidizer
		<3 ppmv H2S outlet of tail gas treatment unit

The performance of several recent sulfur recovery units operated by the refineries located outside of the SCAQMD is shown in Table 5-5. The units were designed to meet 99%-99.9% sulfur recovery efficiency.

[29] According to the *2nd Round of Comments on RECLAIM SOx Shave Staff Report Part I*, dated July 1, 2008, the unit is designed to meet less than 200 ppmv, 12-hour rolling average, which is the limit of NSP~~A~~S Subpart J/Ja. The unit has a mass limit of 135 tons per year, which can be translated to 150 ppmv SOx. The system was started in July 2006, was in operation for about 4 months, was shutdown due to equipment problems outside of the Cansolv system, and is currently not in operation.

[30] Hydrocarbon Engineering Word Review, 2007. www.worldcoal.com/Hydrocarbon/HE_world_review_usa.htm

[31] *Integrating Cansolv® System Technology into the Sour Gas Treating/Sulfur Recovery Plant* which indicated that Cansolv system can be designed to achieve 10 ppmv SO2. www.cansolv.com.

[32] *The Cansolv system process: A new paradigm for SO2 recover and recycle.* J.N. Sarlis and P.M. Ravary of Cansolv Technologies, Inc.

TABLE 5-5
Performance of Sulfur Recovery – Tail Gas Treatment Unit

Company	Source	SOx Standard
Arizona Clean Fuels Yuma LLC, Yuma AZ (1)	SRU - Tail Gas (Amine) Unit - Sour Water Stripper	99.97% sulfur recovery efficiency
BP, Texas City, Texas (2)	SRU	99% sulfur recovery. All refinery fuel gas is scrubbed to remove sulfur. Significant reductions by routing vent streams from the SRU to the front end of the SRU, to recover additional sulfur instead of combusting sulfur to SO2.
Shell Martinez, Contra Costa County, Bay Area (3)	SRU SCOT and tail gas thermal oxidizer	Limit at 50 ppmv at 0% O2. Test showed 13 ppmv SO2 and <0.1 ppmv H2S at 0% O2.
Marathon Petroleum Garyville Refinery, Louisiana (1)	SRU with thermal oxidizers and oxygen enrichment	93 ppmvd SO2 at 0% excess air, 99.9% sulfur recovery, 99.5% thermal oxidizer efficiency

Note: 1) The U.S. Environmental Protection Agency RACT/BACT/LAER Clearinghouse; 2) *BP Texas City Site – Texas City, Texas – 2004 Environmental Statement*, June 2005; 3) CARB BACT Clearinghouse.

Wet gas scrubbing technique is currently used at two refineries in Wyoming, the Sinclair Oil refinery and the Casper refinery since 2004. Results of a full scale testing at Sinclair refinery in November 2005 are shown in Table 5-4. The system was proven to be 99.99% in sulfur removal efficiency and resulted in SO2 outlet concentrations below 0.5 ppmv. In January 2005, Sinclair Oil Corporation decided to install a third DynaWave scrubber at its Tula refinery which has already started up in 2006. The most recent 6-months CEMS data provided to the District by the Wyoming air quality control office confirmed the achieved-in-practice performance for the DynaWave wet gas scrubbers at the level below 5 ppmv.

TABLE 5-~~7~~6
Full-Scale Performance of DynaWave Non-regenerative Scrubber for Sulfur Recovery Unit at Sinclair Refinery

	Run 1	Run 2	Run 3	Average
SO2 inlet, lbs/hr	276.10	259.13	249.50	261.58
SO2 outlet, lbs/hr	0.01	0.01	0.01	0.01
SO2 outlet, ppmv	0.31	0.31	0.31	0.31
SO2, % Removal	99.99	99.99	99.99	99.99

Note: Based on EPA Source Test Method 6. The 0.31 ppmv is the lowest detection level for stack testing. From *Improving Sulfur Recovery Units*, E. Juno of Sinclair Oil Corporation, S.F. Myer and C. Kulczycki of MECS, and N. Watts of CEntry Constructors and Engineers, Petroleum Technical Quarterly, Quarter 3 of 2006.

5.5 BARCT Level and Emission Reductions

Through the data provided to the consultants, there was one refinery regularly vented the flue gas to the atmosphere, and the remaining refineries treated or incinerated the tail gas from their SRU/TG systems. Because of this distinction in the refinery's operations, the consultants divided their recommendations for SRU/TG into two areas.

— For uncombusted tail gas, the consultants recommended a BARCT level of NSPS Subpart J (Ja), namely 10 ppm H_2S and 300 ppm reduced sulfur species (total of H_2S, COS, and CS_2)

— For the combusted tail gas, the consultants recommended 5 ppmv SOx @ 0% O_2 as BARCT. The consultants indicated a level of 10 ppmv would allow a greater number of refineries to meet the overall BARCT level by the gas treatment methods without having to install a wet gas scrubber.

TABLE 5-7
Initial Emission Reductions and Cost Effectiveness Estimated by ETS/AEC for SRU/TGs

Refinery:	1	2	3	4	5	6	Total
Emission Reductions (tpd)	0.13*	0.17	0.15	0.04	0.06	0.29	0.83
Cost Effectiveness based on ETS/AEC ($/ton)	$22.4k	$39.0k	$12.9k	$54.7k	$123k	$36.3k	$37.4k

*Already met the emission reductions

Staff concurred with the recommendations of the consultants on the level of proposed BARCT, except that staff will not require any BARCT with low cost effectiveness (>$50 K per ton). The emission reductions estimated by staff is as follows:

TABLE 5-8
Staff's Proposed Emission Reductions and Cost Effectiveness for SRU/TGs

Refinery:	2	3	6	Total
Emission Reductions (tpd)	0.17	0.15	0.29	0.73
Cost Effectiveness ($/ton)	$39.0k	$12.9k	$36.3k	~~$26k~~$31.5k
Cost Effectiveness based on input from NEC ($/ton)	$49.6k	$55.3k	$41.6k	$44.5k

~~* Already met the emission reductions~~

Chapter 6 – Sulfuric Acid Manufacturing

6.1 Process Description

Sulfuric acid manufacturing process, as shown in Figure 6-1, includes three basic operations. First, sulfur in the feedstock is oxidized and spent sulfuric acid is decomposed to sulfur dioxide (SO_2) in a furnace:

$$S + O_2 = SO_2$$
$$\text{Spent } H_2SO_4 = H_2O + ½\ O_2 + SO_2$$

The sulfur dioxide is then catalytically oxidized to sulfur trioxide (SO_3) in a multi-staged catalytic reactor (or converter). A typical catalyst used in the reactor is vanadium:

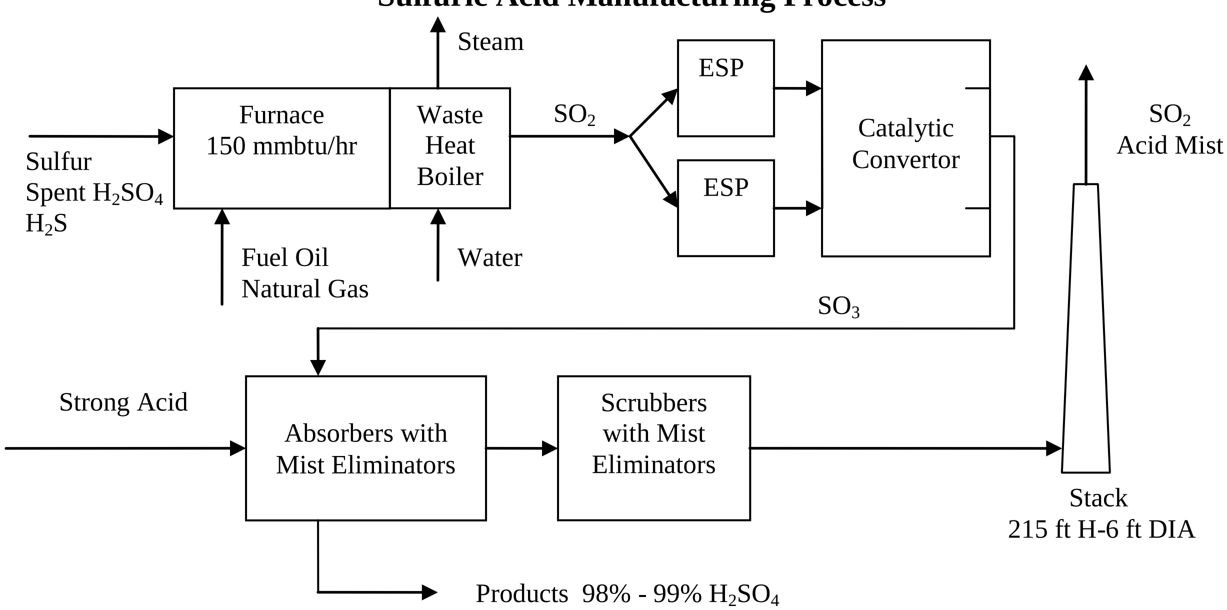
$$2SO_2 + O_2 = 2SO_3$$

The sulfur trioxide reacts with water in a absorbing tower to produce a strong sulfuric acid solution.

$$SO_3 + H_2O = H_2SO_4$$

In a double absorption process, the SO_3 gas formed from the primary converter is sent to a first absorber where the SO3 is removed to form H_2SO_4. The remaining unconverted SO_2 and SO_3 are directed to a second set of converter and absorber to further produce H_2SO_4.

FIGURE 6-1
Sulfuric Acid Manufacturing Process



The conversion to H_2SO_4 is always incomplete, and is affected by the number of stages in the catalytic converter, the type and amount of catalyst used, temperature and pressure, and the concentrations of the reactants, SO_2 and O_2. A 98% - 99% conversion to H_2SO_4 is typical. The exhaust gas stream from the absorbers can be vented to ESPs, scrubbers, and mist eliminators to remove SO_2 and acid mist prior to venting to the atmosphere. The process produces a great deal of heat. Steam driven compressors, waste heat boilers, and heat exchangers are utilized throughout the process to recover and convert the waste heat into useful energy.

6.2 Current Allocations and Emissions

6.2.1 Allocations

Facility A and B are the two facilities in the District that operate a sulfuric acid manufacturing plants. In 1993, allocations were provided to these processes based on an emission factor ranging from 4 lbs/ton acid produced to 9.478 lbs/ton acid produced. The existing SCAQMD Rule 469 limits the SO2 concentration in effluent process gas from a sulfuric acid unit to 500 ppmv and the mass emissions to 198.5 lbs/hr of sulfur compounds expressed as SO2; and NSPS requires a sulfuric acid manufacturing plant to meet an emission level of 4 lb SO_2 per ton of 100% acid produced, maximum 2 hour average. The allocations provided to these two facilities are shown in Table 6-1.

TABLE 6-1
Allocations for Sulfuric Acid Furnace/Reactor

Facility	Peak Year	Emission Factor (lbs per ton acid produced)	Allocations (lbs/year)	Allocations (tons/day)
A	1988	4.000	598,028	0.82
B (Plant 1)	1987	4.380	371,139	0.51
B (Plant 2)	1987	4.577	329,031	0.45
B (Plant 3)	1989	9.478	549,904	0.75
			Total	**2.53**

Note: Prior to 1990, Facility B operated three sulfuric acid units that were built between the late 1920's and late 1950's. In 1990, these three furnaces were replaced with a double absorption furnace to achieve 99.85% conversion efficiency and currently subject to EPA Consent Decree limiting the emission rate to 1.7 lbs SO2 per ton of acid produced.

In addition to SO_2, there is acid mist generated from the absorber of the sulfuric acid manufacturing process. Acid mist is generated when SO_3 combines with water at temperature below the dew point of SO_3. Acid mist is a very stable compound and usually is controlled and captured by mist eliminators. Sulfuric acid mist is limited to 0.15 lbs per ton acid produced under NSPS and 0.30 lbs per ton acid produced under SCAQMD Rule 469.

6.2.2 Emissions

The 2005 emissions reported from these processes are presented in Table 6-2. Facility B reported 1.13 tons per day and Facility A reported 0.04 tons per day.
The two facilities also reported their 2006 and 2007 emissions through the SCAQMD Survey conducted in 2008, as shown in Table 6-2. The production rate of 100% sulfuric acid at Facility B is approximately 3 times larger than the production rate at Facility A.

TABLE 6-2
SO2 Emissions from Sulfuric Acid Furnace/Reactor

Facility	Device Description	2005 Emissions (tons/day)	2006 Emissions (tons/day)	2007 Emissions (tons/day)
A	Reactor	0.04 (1)	0.06	0.05
B	Furnace	1.13 (2)	1.02	0.96
		1.17	**1.08**	**1.01**

Note: 1) The emissions are from a single absorption unit and controlled by a Cansolv scrubber, 2) The emissions are from a double absorption unit.

The emissions from Facility A's reactor are low compared to the emissions from Facility B's furnace. Facility A's single absorption unit uses a Cansolv scrubber to control their SOx emissions from the reactor, whereas the emission from Facility B's double absorption unit is currently not controlled by scrubbers. The SOx outlet concentrations from Facility B's furnace were in a range of 144 ppmv – 185 ppmv, whereas the SOx outlet concentrations from Facility A's reactor were in a range of 17 ppmv – 51 ppmv. The emission rates calculated based on the information reported through the 2008 Survey are from 1.58 lbs/ton – 1.84 lbs/ton acid produced for Facility B, and 0.28 lbs/ton acid for Facility A.

6.3 Control Technology

6.3.1 EPA BARCT Clearinghouse

Staff researched the U.S. EPA RACT/BACT/LAER Clearinghouse to identify the BARCT level for sulfuric acid manufacturing plant. A summary of the information posted on the Clearinghouse is presented in Table 6-3. [33]

In general, in addition to double absorption, the sulfuric acid manufacturing plants in the U.S. have upgraded their converters and absorbers, used cesium promoted vanadium catalysts, and added tail gas scrubbers to meet an emission level ranging from 0.2 lbs – 3.5 lbs SOx per ton of 100% acid produced.

6.3.2 Clean Air Act Settlements

Recently in 2007, the U.S. Department of Justice and the U.S. EPA have announced several Clean Air Act settlements with two major sulfuric acid plants in the country to lower the SO2 emissions from their sulfuric acid plants in the country.

[33] U.S. EPA RACT/ EPA RACT/BACT/LAER Clearinghouse.

TABLE 6-3
Emission Levels for Sulfuric Acid Manufacturing Plants [(1)]

Facility	Source	SOx Level
Dupont, Union, New Jersey (New Construction in 2007)	Two identical 400 tons per day double absorption sulfuric acid plants that use spent acid, sulfur, and hydrogen sulfide as feed stocks.	– 0.2 lbs SOx per ton of 100% acid produced and 3 lbs/hr SOx at 3-hour average – 0.10 lbs sulfuric acid mist per ton of 100% acid produced.
Dupont, El Paso, Texas (New Construction in 2007)	Double absorption sulfuric acid plant that use spent acid and hydrogen sulfide as feed stocks.	– 1 lbs SOx per ton of 100% acid produced at 3-hour average – 0.10 lbs sulfuric acid mist per ton of 100% acid produced.
Dupont, New Castle, DE (New Construction in 2005)	Double absorption sulfuric acid plant, 550 tons per day, that use spent acid and hydrogen sulfide as feed stocks.	– 1.35 lbs SOx per ton of 100% acid produced at 3-hour average – 0.12 lbs sulfuric acid mist per ton of 100% acid produced.
General Chemical LLC, Augusta, Richmond	Double absorption sulfuric acid plant, 1,000 tons per day. A new soda ash scrubber was used to lower the standard from 4 lbs to 2.6 lbs/ton	– 2.6 lbs SOx per ton of 100% acid produced at 3-hour average – 0.08 lbs sulfuric acid mist per ton of 100% acid produced.
CF Industries, Hillsborough, Florida	Double absorption plant, 1,600 tons/day, uses spent acid, sulfur, and hydrogen sulfide as feed stocks. This plant has a two-stage ammonia scrubber and upgraded converters. The plant uses cesium catalysts to increase the SO2-SO3 conversion.	– 3.5 lbs SOx per ton of 100% acid produced, 99.5% conversion, and 401 lbs/hr SOx at 3-hour avg. – 0.10 lbs sulfuric acid mist per ton of 100% acid produced, 99% control efficiency, and 11 lbs/hr sulfuric acid mist.
CF Industries, Plant City, Florida	Two 2,750 tons per day double absorption plants that use spent acid, sulfur, and hydrogen sulfide as feed stocks. The converters and absorbers were upgraded and cesium promoted vanadium catalysts were used to increase the SO2-SO3 conversion.	– 3.5 lbs SOx per ton of 100% acid produced, 99.5% conversion, and 401 lbs/hr SOx at 3-hour average – 0.10 lbs sulfuric acid mist per ton of 100% acid produced, 99% control efficiency, and 11 lbs/hr sulfuric acid mist.
US Agri-Chemicals Corp., Polk, Florida	A 3,000 tons per day double absorption sulfuric acid plant with mist eliminators	– A 3.5 lbs SOx per ton 100% acid produced, and 99.9% conversion efficiency, and 1916 tons per year – 0.12 lbs sulfuric acid mist per ton of 100% acid produced, 99% control efficiency, and 65.7 tons per year sulfuric acid mist.

Note: 1) EPA RACT/BACT/LAER Clearinghouse on EPA's web page conducted in November 2007.

- Company #1 operates four sulfuric acid plants in Louisiana, Virginia, Ohio, and Kentucky. Under the recent settlements, the company has agreed to install $66 million state-of-the-art dual absorption control equipment in its largest plant located in Darrow, Louisiana. For the other three plants, the company has the option to install the $87 million additional control technologies or ceasing operations. All four plants have to meet the lower standards ranging from 1.7 lbs – 2.4 lbs SO_2 per ton acid produced by March 1, 2012. When fully implemented, these plants will reduce SOx by an additional 90%. A summary of these agreements is included in Table 6-4. [34]

– Company #2 has agreed to spend approximately $50 million to upgrade air pollution control at their eight production plants in four states across the country to reduce SO_2 emissions by approximately 95%. As shown in Table 6-4, the consent decree requires the installation of wet gas scrubbers or double absorption technology to meet the BARCT levels ranging from 1.7 lbs – 2.5 lbs SOx per ton acid produced. [35]

TABLE 6-4
Consent Decree for Sulfuric Acid Manufacturing Plants

Company	SOx Level (lbs SO_2 per ton)	Compliance Date
#1, Burnside, Darrow, Louisiana	2.4 (1)	September 1, 2009
#1, James River, Richmond, Virginia	1.5 (1)	March 1, 2010
#1, Fort Hill, North Bend, Ohio	2.2 (1)	March 1, 2012
#1, Wurtland, Wurtland, Kentucky	1.7 (1)	March 1, 2012
#2, Hammond, Indiana (3)	2.5 (2)	Not specified
#2, Martinez, California (4)	2.2 (2)	Not specified
#2, Dominguez, California (3)	1.7 (2)	Not specified
#2, Bayton, Texas (4)	2.2 (2)	Not specified
#2, Houston #8, Texas (5)	1.7 (2)	Not specified
#2, Houston #2, Texas (5)	1.8 (2)	Not specified
#2, Baton Rouge #2, Louisiana (5)	2.2 (2)	Not specified
#2, Baton Rouge #1 Louisiana (5)	1.9 (2)	Not specified

Note: 1) the standard is a 3-hour rolling average. 2) The standard is a 365-day rolling average. Company #2 plants must meet 0.15 lbs/ton acid mist. 3) Double absorption plant. 4) Single absorption with ammonia scrubber. 5) Single absorption with caustic scrubber.

6.4 Proposed BARCT Level and Emission Reductions

As shown in Tables 6-3 and 6-4, the controlled emission level for sulfuric acid manufacturing plants has been improved significantly. The current controlled level can be as low as 0.2 lbs/ton – 0.3 lbs/ton. These levels could be achieved by upgrading the converters and absorbers, using cesium promoted vanadium catalysts, and/or adding tail gas scrubbers.

In the District, Facility A has used Cansolv scrubber to control SOx emissions from its acid production plant, and achieved 0.28 lbs/ton acid produced. As a result, the emissions from its reactor have dropped from 0.82 tons per day in 1993 to 0.04 tons per day in 2005. By using Cansolv scrubber, Facility A has achieved an emission reduction of approximately (1-0.04/0.82)*100 = 95%.

[34] Civil Clean Air Act Settlements. www.usdoj.gov

[35] Civil Clean Air Act Settlement, www.uepa.gov/compliance/resources/cases/civil/caa/rhodia-fcsht.html

The emissions from Facility B's furnace are currently not vented to scrubbers.[36] The SOx emissions from this facility's furnace were in a range of 144 ppmv – 185 ppmv, and this furnace is the #1 SOx emitter in the District at 1.13 tons per day in 2005.

The consultant's analyses (NEXIDEA) for the feasibility and costs of control are summarized in Part 2 of the Staff Report, and the non-confidential portions of the analys~~i~~es (NEXIDEA & NEC) are~~is~~ available for public information. After considering all feasible technologies, the consultants'~~s~~ recommendation for BARCT level, which staff concurred with, is 10 ppmv for sulfuric acid plants. The consultants'~~s~~ estimates are as follows:

TABLE 6-5
Emission Reductions and Cost Effectiveness Estimated by NEXIDEA
~~-~~and Cost Effectiveness Estimated Based on Input from NEC

~~Equipment~~	BARCT Level	Emission Reductions	Cost Effectiveness
~~Facilities A and B~~NEXIDEA	0.14 lbs SOx/ton acid (10 ppmv)	<0.~~1~~03 tpd (Facility A) 1~~.1~~ tpd (Facility B)	$1.~~4~~9~~K~~k - $5.6~~K~~k Average: $2.0k
NEC	0.14 lbs SOx/ton acid (10 ppmv)	<0.03 tpd (Facility A) 1 tpd (Facility B)	$2.8k - $8.8k Average: $3.4k

Comparing to an average Tier I level of ~~5.08~~3.93 lbs/ton, the proposed new BARCT of 0.14 lbs/ton reflects a 97% reduction from Tier I level.

[36] Permit condition no A72.1 in Facility B's Facility Permit, dated September 2007. The 99.9% efficiency seems not correlated well with the SOx outlet concentrations recorded in the range of 144 – 185 ppmv from the furnace.

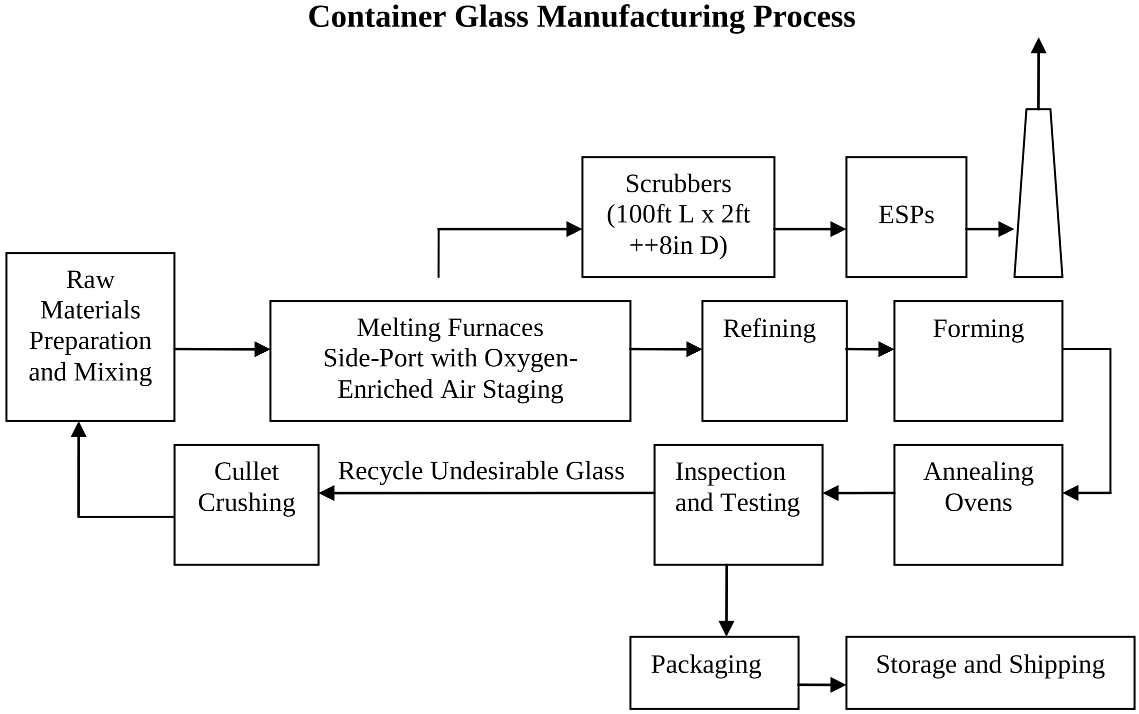
Chapter 7 – Container Glass Melting Furnaces

7.1 Process Description

Owens-Brockway Glass Container Inc. is a container glass manufacturing facility located in Vernon. The company manufactures glass bottles, glass wares, pressed & blown glass, tempered glass, as well as safety glass. The manufacturing process contains four phases 1) preparation of raw material, 2) melting in a furnace, 3) forming, and 4) finishing. Figure 7-1 is a simplified diagram for a typical glass manufacturing process.

Raw materials, which include sand, limestone, and soda ash, are crushed and mixed with cullets to ensure homogeneous melting. The raw materials are then conveyed to a continuous regenerative side-port melting furnace. As the materials enter the melting furnace through a feeder, they float on the top of the molten glass already in the furnace, melt, and eventually flow to a refiner section, and then fore hearths, forming machine, and annealing ovens. The final products undergo inspection, testing, packaging and storage. Any damaged or undesirable glass is transferred back to be used as cullets.

FIGURE 7-1
Container Glass Manufacturing Process



Sulfur oxides are generated from the decomposition of the sulfates in the raw materials and sulfur in the fuel. The melting furnace contributes over 99% of the total emissions from a glass plant. There are currently two melting furnaces at the Vernon facility, 60 mmbtu/hr furnace #23B (Device D147), and 100 mmbtu/hr furnace #23C (Device ID D112). Each furnace is limited to approximately 400 tons glass pulled per day. The SOx emissions are controlled by two scrubbers, of which one scrubber has a permit condition of 80% efficiency. The scrubbers are manufactured by PPC Industries, use sodium bi/sesquicarbonate as scrubbing agent, have two passes, and about 101 ft in length and 2ft 8 in diameter. The outlet flue gases from the scrubbers are directed to a common manifold and are vented to three dry ESPs downstream, one standby, for particulate emissions control. The furnaces currently have oxygen-enriched air staging (oxy-fuel), a control technique that is commonly used to reduce NOx.

7.2 Current Allocations and Emissions

7.2.1 Allocations

The allocations provided to the facility for their furnaces are presented in Table 7-1. These allocations were estimated based on SOx emission factors ranging from 2.12 lbs/ton to 3.15 lbs/ton of glass pulled and their peak activities in 1992. The total allocations provided for the three furnaces were 1.01 tons per day.

TABLE 7-1
Allocations for Container Glass Melting Furnaces

Equipment	Peak Year	Emission Factor (lbs per ton glass)	Allocations (lbs/year)	Allocations (tons/day)
Furnace #1	1992	3.150	231,475	0.32
Furnace #2	1992	2.480	269,673	0.37
Furnace #3	1992	2.120	237,605	0.33
			Total	**1.01**

7.2.2 Emissions

The emissions reported in 2005, 2006 and 2007 from Owens-Brockway's furnaces are presented in Table 7-2. In total, the two furnaces emitted about 0.21 tons per day SOx in 2005, 0.27 tons per day in 2006, and 0.35 tons per day in 2007. The emissions from the two furnaces were vented to two scrubbers (one scrubber dedicated to each furnace); and three parallel ESPs (shared between two furnaces). The emissions were measured by three CEMS. The SOx outlet concentrations were averaged 64 ppmv for the first CEMS, 69 ppmv for the second CEMS, and 85 ppmv for the third CEMS. In addition to Owens-Brockway, Saint-Gobains Containers Inc. operated a 78 mmbtu/hr glass melting furnace that emitted about 0.13 tons per day SOx in 2005, but this operation has ceased since then.

TABLE 7-2
SOx Emissions from Glass Melting Furnaces

Facility	SOx Avg Concentration (ppmv)	2005 Emissions (tons/day)	2006 Emissions (tons/day)	2007 Emissions (tons/day)
Owens-Brockway, A CEMS	64	0.076	0.27	0.35
Owens-Brockway, B CEMS	69	0.084		
Owens-Brockway, C CEMS	85	0.036		
Saint-Gobain (shutdown)	NA	0.128	NA	NA
		0.32	**0.27**	**0.35**

Note: The 2005 SOx emissions were from SCAQMD database for the period from January 2005 – December 2005. The 2006 and 2007 emissions were reported by the facilities through a Survey Questionnaire distributed by SCAQMD in 2008.

Through the 2008 Survey, Owens-Brockway reported that the two furnaces were in operating at > 90% maximum rated capacity from 2005-2007 and have emission rates ranging from 0.62 lbs/ton – 1.05 lbs/ton glass pulled, as shown in Table 7-3.

TABLE 7-3
SOx Emission Rates from Glass Melting Furnaces

Year	SOx Emission Rates (Lbs/Ton of Glass Pulled)
2005	0.62
2006	0.80
2007	1.05

7.3 Control Technology

In 2005, the U.S. Department of Justice and the U.S. EPA have reached an agreement with Saint-Gobain Containers, Inc. and required Saint-Gobain to install state-of-the-art pollution control at a cost of $6.6 million to reduce SO2 emissions from their melting furnaces. The Saint-Gobain plant located in Seattle Washington was permitted to a level of 1.6 lbs SOx per ton glass produced with the use of Tri-Mer Cloud Chamber Scrubber (CCS). [37] The installation of the CCS was just recently finished, and the plant started testing in mid of December 2007. The capital costs for the CCS at this plant were approximately $1,694,000, designed for an inlet flow of 40,000 acfm at 700 degree F. [38]

Other Saint-Gobain facilities must meet a level of 0.8 lbs SO2 per ton of glass pulled. This 0.8 lbs/ton is the most recent BARCT level for container glass melting furnaces and has been

[37] Title V Permit & Statement of Basis for Saint-Gobain Containers Inc. located in Seattle prepared by the Puget Sound Clean Air Agency, dated June 6, 2007.

[38] E-mail from Mr. Gerry Pade of Pudget Sound Clean Air Agency to Minh Pham, dated November 30, 2007.

proposed by San Joaquin Valley APCD in their proposed rule 4354. [39, 40] Tri-Mer Corporation estimates that their technology can achieve a level as low as 0.1 lbs SO2 per ton of glass produced, 0.1 ppmv outlet SO2, and 99.9% control efficiency. The BARCT information for glass melting furnaces is summarized in Table 7-3.

TABLE 7-3
BARCT for Container Glass Manufacturing Plant

Facility	SOx Level
Saint-Gobain Containers, Inc., Seattle, Washington (Tri-Mer Cloud Chamber Scrubber)	Permitted at 1.6 lbs per ton glass produced. Source tested at 0.01 lbs per ton glass (1, 2, 3)
San Joaquin Valley APCD Rule 4354	0.9 lbs/ton glass produced
Tri-Mer Cloud Chamber Scrubber	0.1 ppmv SO2 outlet 0.1 lbs per ton glass produced 99.9% control efficiency (4)

Note: 1) This is the permitted level of SOx from Saint-Gobain furnaces controlled by a Tri-Mer Cloud Chamber Scrubber which was designed to handle an exhaust flow of 40,000 acfm at 700 deg F. The furnaces are either operated at a) 205 tons per day capacity with an exhaust flow rate of 35,600 acfm at 350 deg F, or b) 195 tons per day capacity with an exhaust flow rate of 15,000 acfm at 500 F. 2) Fuel oil burning in these furnaces is limited to 15 ppmv by weight of sulfur (0.0015%). 3) Based on the most recent source test at this facility in September 2009, the facility achieved an outlet SOx concentrations between 0.2 – 0.7 ppmv at 99% control efficiency which resulted in about 0.01 lbs SOx per ton glass. 4) Information provided by Tri-Mer Corporation based on their own source testing information.

7.4 BARCT Level and Emission Reductions

As noted earlier, ~~Given that~~ Owens Brockway achieved a level of 0.62 lbs/ton in 2005, averaged 64 ppmv - 85 ppmv SOx, with the use of dry scrubbing. ~~, and Tri-Mer Cloud Chamber wet scrubber at~~ Saint-Gobain Containers Inc. in Seattle Washington, with the use of Tri-Mer Cloud Chamber scrubber, can achieve an emission rate of 0.01 - 0.1 lbs/ton, or an outlet concentration of 0.1 ppmv – 0.7 ppmv SOx, further emission reductions from container glass manufacturing is feasible.

The consultant~~s~~ (ETS, Inc.)'s recommendation for BARCT is a level of 1 ppmv or below:

TABLE 7-4
Emission Reductions and Cost Effectiveness Estimated by ETS

Equipment	BARCT Level	BARCT Emission Level	Emission Reductions	Cost-Effectiveness
Owens-Brockway A, B & C CEMS	99% control (≤1 ppmv)	0.0058 lbs/ton glass pulled	0.19 tpd	$ 5.201 K/ton

[39] Consent Decree for Saint-Gobain Containers, Inc. www.epa.gov/compliance/resources/reports/endofyear/eoy2005/2005aircasehighlights.html.

[40] San Joaquin Valley APCD Rule 4354 – Glass Melting Furnaces, Proposed Amended Rule and Draft Staff Report, dated February 8, 2008.

This is the only container glass facility in the basin. Because of the economic reason, s~~S~~taff's recommendation for BARCT is 5 ppmv or below. The emission reductions and cost effectiveness are in Table 7-5.

TABLE 7-5
Staff's Proposed Emission Reductions and Cost Effectiveness for Glass Furnace

Equipment	BARCT Level	BARCT Emission Level	Emission Reductions	Cost-Effectiveness
Owens-Brockway A, B & C CEMS	95% control (≤5 ppmv)	0.03 lbs/ton glass pulled	0.19 tpd	$ 5.198 K/ton

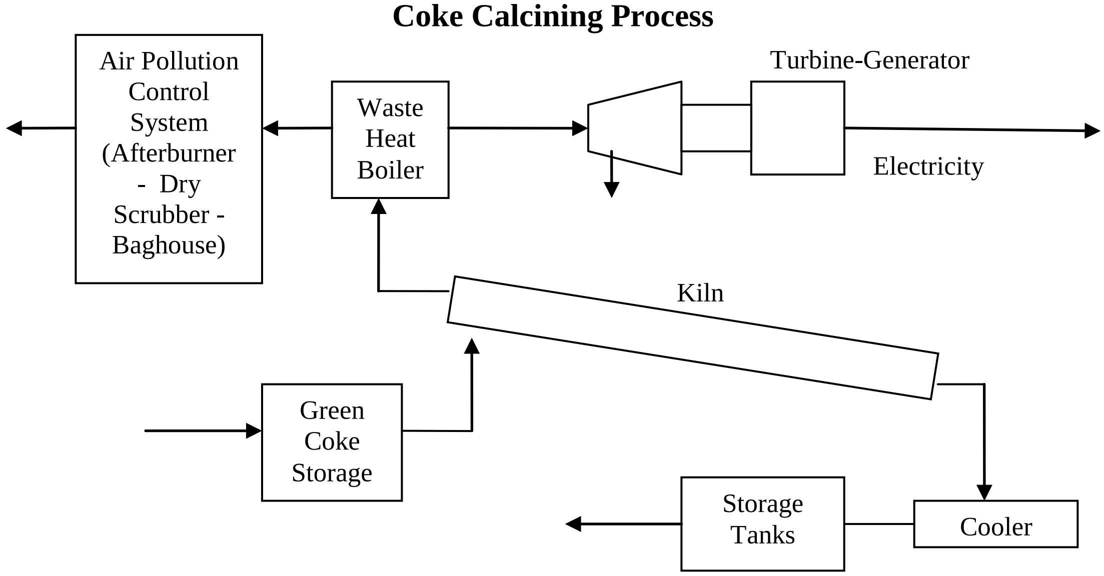
Chapter 8 – Coke Calcining

8.1 Process Description

Engineering of the coke facility began in 1978 by Martin-Marietta. Initial production of calcined coke occurred in February 1983. The company was purchased by BP Products Company in 1985. BP produces calcined coke in two locations in the United States: Wilmington California and Cherry Point Washington, and two locations in Germany: Gelsenkirchen and Lingen.

Basically, coke calcining is a process to improve the quality and value of "green coke" produced at a delayed coker in a refinery. At BP Wilmington, the green feed, produced by BP's nearby Carson Refinery, is screened and transported to the BP Wilmington Calciner by truck, where it is stored under cover in a coke storage barn. The screened and dried green coke is introduced into the high end of the rotary kiln, 3 feet diameter x 270 ft long, is tumbled by rotation, moves down the kiln countercurrent to a hot stream of combustion air produced by the combustion of natural gas or oil. The kiln temperatures are in a range of 2000 – 2500 degrees Fahrenheit. The green coke is retained in the kiln for approximately one hour to drive off the moisture, impurities, and hydrocarbon. After discharging from the kiln, the calcined coke drops into a cooling chamber, where it is quenched with water, treated with dedusting agents for dust control, carried by conveyors to storage tanks, and later are transported by trucks to the Port of Long Beach for export, or is loaded into railcars for shipments to domestic customers. A simplified process diagram of the calcining process is shown in Figure 8-1.

FIGURE 8-1
Coke Calcining Process



BP Wilmington produces approximately 400,000 short tons per year of calcined products.[41] The Wilmington coke calciner is limited to a maximum processing rate of 1,980 tons green coke per day, and is increasing to 2,400 tons of green coke per day.[42] BP Wilmington is a global supplier of calcined coke to the aluminum industry, and fuel grade coke to the fuel, cement, steel, calciner, and specialty chemicals businesses.

8.2 Current Allocations and Emissions

8.2.1 Allocations

As shown in Table 8-1, the allocations for BP coke calciner was estimated based on a controlled emission factor of 2.473 lbs SOx per ton of calcined coke and a production rate of 378,264 tons calcined coke. [43] The coke calciner was in compliance with SCAQMD Rule 1119 – Petroleum Coke Calcining Operations – Oxides of Sulfur, adopted March 2, 1979, which requires that the uncontrolled SOx emissions from coke calcining operations must be reduced by at least 80% by July 1, 1983.

TABLE 8-1
Allocations for BP Coke Calciner

Peak Year	Emission Factor (lbs per ton coke)	Allocations (lbs/year)	Allocations (tons/day)
1989	2.473	935,447	1.28
		Total	**1.28**

8.2.2 Emissions

The 2005-2007 reported emissions from BP coke calciner are presented in Table 8-2. Note that the 2005-2007 emissions are much less than the allocations provided to BP in 1993.

TABLE 8-2
SOx Emissions from BP Coke Calciner

Device ID	Rating (mmbtu/hr)	2005 Emissions (tons/day)	2006 Emissions (tons/day)	2007 Emissions (tons/day)
20	120	0.35	0.62	0.55
	Total	**0.35**	**0.62**	**0.55**

Note: The 2005 SOx emissions were from SCAQMD database for the period from January 2005 – December 2005. The 2006 and 2007 emissions were reported by the facilities through a Survey Questionnaire distributed by SCAQMD in 2008.

[41] BP Coke at Wilmington, http://coke.bp.com/tech/tech.cfm, September 2007.

[42] *SCAQMD Facility Permit to Operate of BP West Coast Products LLC, BP Wilmington*, Draft, Version September 2007.

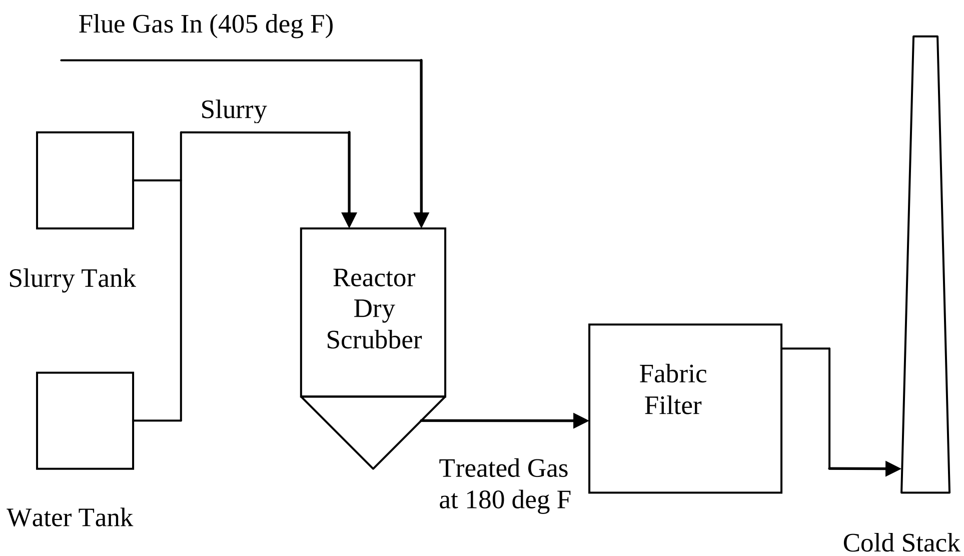
[43] SCAQMD Tier I Emission Rate, RECLAIM, 2002

8.3 Control Technology

8.3.1 Dry Scrubber at BP Wilmington

Dry scrubbing is the chosen control technology for the BP Wilmington coke calciner. The control system includes a spray dryer, a reverse-air baghouse, a slurry storage system, a slurry circulating system, and a pneumatic conveying system. Calcium hydroxide (CaOH) slurry is the absorbing medium for SO_2 control. Figure 8-2 shows a simplified process diagram for the dry scrubber system at BP Wilmington..

FIGURE 8-2
Dry FGD System for Coke Calciner at BP Wilmington



The system was designed and guaranteed to achieve 90% control efficiency for SOx at a calcined coke capacity of 54 tons/hour (1,296 tons/day or 473,040 tons/year). The SOx emission rates were tested in July 1983 to provide verification of guarantees. Production rate during the tests averaged 50 tons per hour and the emission rates ranged from 0.21 lbs/ton – 1.64 lbs/ton, averaged at 1 lbs/ton coke.[44] It should be noted that the Tier I controlled emission level of SOx from the calciner provided in 1993 is 2.47 lbs/ton coke, even though the system was designed and tested to meet lower levels than 2.47 lbs/ton.

A recent source test conducted at BP Wilmington calciner kiln reported a level of approximately 66 ppmv SOx at a processing rate of 1,848 tons green coke per day. The processing rate was

[44] *Performance of Dry Flue Gas Desulfurization on a Petroleum Coke Kiln Application*, R.J. Horn of Ecolaire Environmental Company and J.F. Bent of Martin Marietta Aluminum, Journal of the Air Pollution Control Association, September 1984.

substantially higher than the processing rate used for the original design at 1,296 tons per day to achieve 90% efficient.[45]

In responding to the 2008 Survey, BP indicated that the performance of the dry scrubber in 2005-2007 exceeded the design levels. The control efficiencies for the dry scrubber in 2005-2007 were in a range of 98% - 99%. The averages of SOx outlet concentrations in 2005-2007 were in a range of 27 ppmv – 43 ppmv, with some RATA tests conducted in 2006 and 2007 showed a higher level at 82 ppmv at 4% O2 and 84 ppmv at 5% O2. BP reported that with the dry scrubber, their emission rates in 2005-2007 were in a range of 0.56 – 0.89 lbs SOx per ton coke. Table 8-3 shows a comparison between design parameters and current performance in 2005-2007.

TABLE 8-3
Design Parameters and Current Performance of
Dry Scrubber for BP Wilmington Coke Calciner

	Design Parameter	2005 Performance	2006 Performance	2007 Performance
Processing Rate (tpd)	1,296			
Control Efficiency (%)	90%	99%	98%	99%
Emission Rate (lbs/ton)	0.21–1.64	0.56	0.97	0.89
SOx Concentration (ppmv)	Not Measured	27 ppmv	52 ppmv	43 ppmv

8.3.2 Wet Scrubber and Wet ESP at BP Cherry Point Refinery

In addition to the coke calciner ay Wilmington, BP operates three calciners at Cherry Point Refinery in Blaine, Washington. Originally, BP voluntary installed a wet scrubber to control SOx. Later, the company removed a portion of the wet scrubber and installed a wet electrostatic precipitator (WESP) to further control sulfuric acid mist emissions from the calciners, as shown in Figure 8-3.

In addition, the company added a baghouse to further control PM. The calciners had an uncontrolled emission rate of 1125 – 1425 ppmv SOx, corrected to 7% O2. With the use of the wet scrubber, the SOx emissions were reduced to about 160 ppmv at 90% control efficiency. With the addition of a WESP, SOx emissions were reduced by 96%, and met a standard of 35 ppmv SO2, corrected to 7% O2, on a daily average basis. The particulate fine including sulfuric acid mist was at 0.01 grains/dscf, corrected to 7% O2.[46, 47] The performance of BP Cherry Point coke calciners is summarized in Table 8-4.

[45] SCAQMD Source Test Report, R01032.

[46] *Air Operating Permit - BP West Coast Products, LLC. Cherry Point Refinery Blaine, Washington, Final Modification.* Northwest Clean Air Agency, September 06, 2006.

[47] *Eliminating a Sulfuric Acid Mist Plume from a Wet Caustic Scrubber on a Petroleum Coke Calciner*, Charles Brown and Paul Hohne of VECO Pacific Inc., Environmental Progress, Vol. 20, No. 3, October 2001.

FIGURE 8-3
FGD System for Coke Calciner at BP Cherry Point

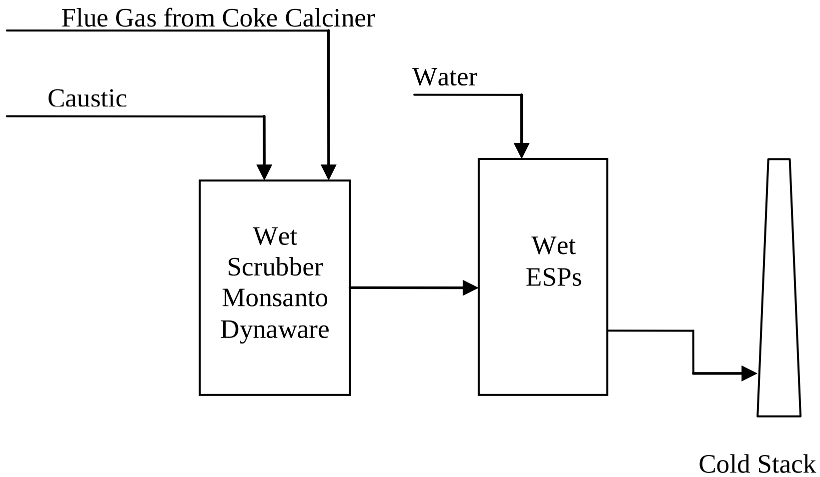


TABLE 8-4
Performance of Wet Scrubber and WESP for BP Cherry Point Coke Calciners

Equipment:	Combination of Wet Scrubber and WESP
Processing Rate:	1,301 tons per day
Control Efficiency:	97% - 98%
Emission Rate:	0.14 lb SOx per ton coke
Outlet Concentration:	35 ppmv Limit (Test Results: 10 -12 ppmv)

8.4 BARCT Level and Emission Reductions

Given the facts that the dry scrubber at BP Wilmington designed up to 90% efficiency could perform at 98% - 99% control efficiencies to achieve emission rates ranging from 0.21 lb – 1.64 lb SOx per ton calcined coke; and that a combination of wet scrubber and wet ESP can achieve 96% control efficiency with an emission rate of 0.14 lb SOx per ton calcined coke, staff believe that further emission reductions from coke calciner is possible.

In September 2008, staff, WSPA and the refineries awarded a contract to NEXIDEA Inc. to conduct a feasibility and costs analysis of control technologies for coke calciner. A summary of the consultant (NEXIDEA)'s analysis is in Part 2 of the draft Staff Report. The consultant's recommendation was 10 ppmv, which reflects ~~80%~~95% additional control above Tier I. Staff concurred with the consultant's recommendation. After reviewing NEXIDEA's cost analysis, NEC also recommended WGS as BARCT for coke calciner, however NEC's cost-effectiveness was much lower as shown in table below.~~Staff adjusted the consultant's estimates of emission reductions and emission rate to be as follows:~~

TABLE 8-5
Emission Reductions and Cost Effectiveness Estimated for Coke Calciner

BARCT Level	BARCT Emission Level	Emission Reductions	Cost-Effectiveness
≤10 ppmv	0.11 lbs/ton calcined coke	0.28 tpd	$ 9,902 per ton per NEXIDEA $23,036 per ton based on input from NEC

Chapter 9 – Portland Cement Manufacturing

9.1 Process Description

There are two Portland cement manufacturing facilities in the Basin, California Portland Cement Company (CPCC) and TXI Riverside Cement Company (TXI). CPCC manufactures gray cement, and TXI manufactures white cement and produces gray cement from clinkers delivered to the facility by railcar. CPCC ranks #10 on the list of top SOx emitters in the District in 2005 with total facility emissions of 100.5 tons per year, whereas TXI is ranked #25 with total facility emissions of 0.7 tons per year. Therefore, staff will only focus on the technology to reduce SOx emissions at CPCC in this amendment.

The production of Portland cement at CPCC is a four step process presented in Figure 9-1 which includes: 1) raw materials acquisition; 2) preparation of raw materials into raw mix; 3) pyroprocessing of raw mix to make clinkers; and 4) grinding and milling of clinkers into cement.

Raw materials for manufacturing cement include calcium, silica, alumina and iron. Calcium is the element of highest concentration, and iron is raw material for gray cement but not used for white cement. These raw materials are obtained from minerals such as limestone for calcium; sand for silica; shale and clay for alumina and silica. CPCC obtains limestone from the quarry located on site. Other raw materials are delivered to CPCC by truck or rail car.

Preparing the raw mix includes crushing, milling, blending and storage. Primary, secondary and tertiary crushers are used to crush the raw materials until they are about ¾ inch or smaller in size. Raw materials are then conveyed to rock storage silos. Belt conveyors are typically used for this transport. Roller mills or ball mills are used to blend and pulverize raw materials into fine powder. Pneumatic conveyors are typically used to transport the fine raw mix to silos for storage until it is used to the pyroprocessing..

Pyroprocessing is the chemical and physical process of transforming the fine raw mix into clinkers. Pyroprocessing occurs in a rotary kiln and includes three steps:

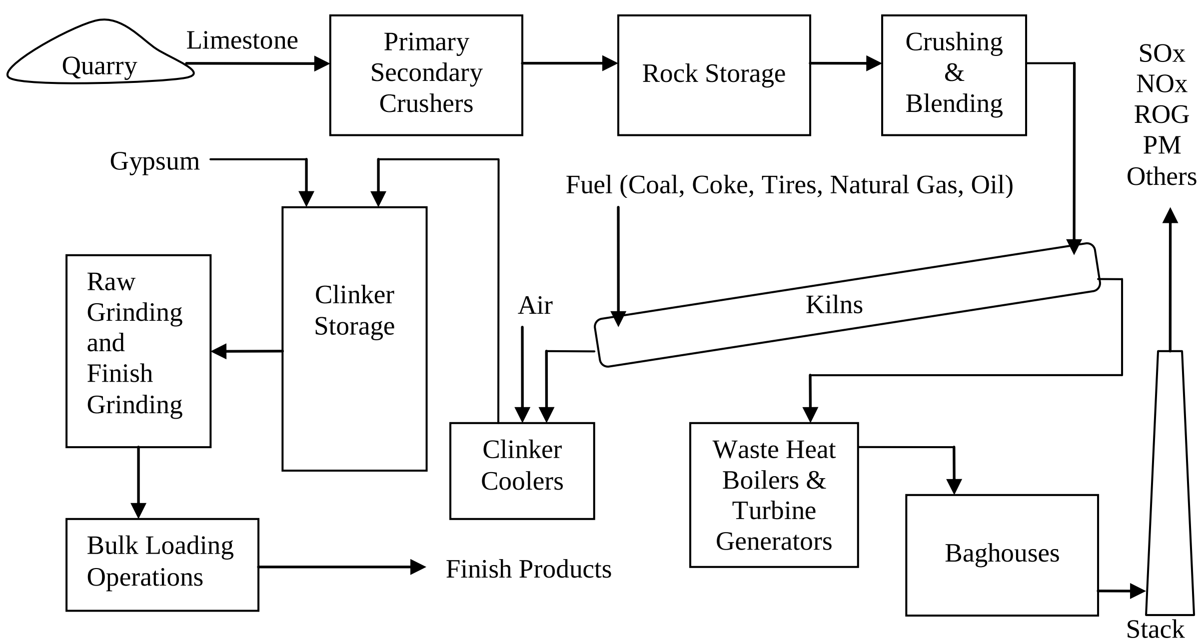
— Evaporating free water and dehydrating to form oxides of silicon, aluminum, and iron. This process occurs in a drying and preheating zone of the rotary kiln at temperatures of about 212 ^{o}F – 800 ^{o}F;

— Calcining of calcium carbonates ($CaCO_3$) to form calcium oxides (CaO) and carbon dioxide (CO_2). This process occurs in the calcining zone of the rotary kiln at temperatures of about 1100 ^{o}F – 1800 ^{o}F; and

— Chemical reacting, melting and restructuring of materials occur between calcium oxides (CaO), silica, alumina and iron to form clinker. Clinker is a solid silicate material ranges in size from 1 inch – 2 inch diameter, and formed in the "burning" zone of the rotary kiln at temperatures of about 2200 ^oF – 2700 ^oF.

The pyroprocessing process at CPCC is called a "long dry process" consisting solely of a simple long rotary kiln. CPCC operates two rotary kilns in parallel, each is 18 ft in diameter and 500 ft in length for gray clinker. The kiln is slightly inclined and rotates on its longitudinal axis. Raw materials are fed into the upper end of the kiln while fuels are burned in the lower end. As the kiln rotates, the raw materials move slowly from the upper end to the lower end, and the combustion gases move in countercurrent direction. The residence time of raw materials in a gray cement kiln is about 2 hours – 3 hours. The hot clinker, which exits at about 2000 ^oF from the kiln, is quickly cooled in the clinker cooler and is conveyed to storage. Clinker is water reactive and should be protected from moisture. If clinker gets wet, it will hydrate and set into concrete. Heat used in the kiln is supplied through the combustion of different fuels such as coal, coke, oil, natural gas, and tires. The combustion gases are vented to baghouse for dust control, and dusts are returned to the process or recycled if they meet certain criteria, or is discarded to landfills.

FIGURE 9-1
Portland Cement Manufacturing Process at CPCC Colton



Grinding and milling clinkers into cement is the last step of the manufacturing process. Up to 5% of gypsum is added to the clinker during this stage to control the setting time of cement. Other specialty chemicals are also added. After grinding and milling, the cement is pneumatically conveyed to the product silos, and either sold in bulk or is bagged.

9.2 Current Allocations and Emissions

9.2.1 Allocations

The allocations provided to CPCC in 1993, as well as the peak activities and emission factors, were presented in Table 9-1. The majority of the allocations was provided to the combustion of coal in boilers/heaters and cement kilns.

TABLE 9-1
Allocations for Kilns and Boilers at CPCC

Equipment	Fuel Type	Peak Yr	Emission Factor	Emissions (lbs/yr)	Emissions (tons/day)
Ovens	Natural Gas	1987	0.83 lbs/mmcf	101	0.00
Boilers/Heaters	Coal	1987	3.055 lbs/ton coal	217,018	0.30
Cement Kilns	Natural Gas	1987	21.45 lbs/mmcf	1,285	0.00
Cement Kilns	Fuel Oil	1987	1.08 lbs/thousand gals	12	0.00
Cement Kilns	Coal	1987	0.351 lbs/ton coal	22,569	0.03
Cement Kilns	Natural Gas	1987	7.55 lbs/mmcf	536	0.00
Cement Kilns	Fuel Oil	1987	3.07 lbs/thousand gals	384	0.00
Cement Kilns	Coal	1987	0.013 lbs/ton coal	948	0.00
				Total	**0.33**

9.2.2 Emissions

The calendar year 2005 reported emissions from CPCC's kilns and steam boiler are presented in Table 9-2. The 2005 facility emissions are still slightly below the overall allocations. However, the emission distribution within the facility was substantially changed: the kilns generated most of the facility emissions in 2005, whereas in 1987, most of the emissions originated from boilers/heaters at CPCC. Particulate matter from the kilns and steam boiler are controlled by baghouses. Limestone used in the kilns and boiler creates an alkaline environment that promotes a direct internal absorption of SO_2. Post combustion control for SOx is not currently used at CPCC.

In responding to a 2008 Survey conducted by the SCAQMD, CPCC reported that the average SOx concentrations from the two kilns were 49 ppmv at 13% O2 (approximately 111 ppmv at 3% O2). The emission rate for the two kilns was approximately 0.5 lbs SOx per ton clinker..

Regarding the coal-fired steam boiler, CPCC reported that the coal-fired steam boiler has not been in operation since 2002, however CPCC may operate the boiler in the near future if circumstances in energy costs or fuel sources change. The boiler used coal and natural gas as combustion fuel. The emission rate for this coal fired boiler was approximately 7 lbs SOx/ton coal.

TABLE 9-2
SOx Emissions from CPCC

	Dev ID	Rating (mmbtu /hr)	SOx Level (ppmv)	2005 Emissions (tpd)	2006 Emissions (tpd)	2007 Emissions (tpd)
Kiln #2	368	260	49 (13% O2)	0.193	0.146	0.186
Kiln #1	321	260	49 (13% O2)	0.074	0.129	0.112
Steam Boiler	851	232	NA	0.002	0.000	0.000
			Total	**0.269**	**0.275**	**0.298**

Note: The 2005 SOx emissions were from SCAQMD database for the period from January 2005 – December 2005. The fiscal year 2006 and 2007 emissions and the SOx concentrations were reported by the facilities through the 2008 Survey.

TABLE 9-3
SOx Emission Rates

	Emission Rate
Kilns	0.5 lbs SOx/ton clinker
Steam Boiler	7 lbs SOx/ton coal

9.3 Control Technology for Coal-Fired Fluidized-Bed Boilers

9.3.1 In-Process Control Technology

The control technologies for coal fired boilers are described abundantly in literature.[48] Almost all SO2 emission control technologies for coal-fired boilers are post-combustion control. The exception to this universal rule is found in the fluidized bed steam boiler (Device ID 851) used at CPCC. Fluidized bed boilers generally operate at about 1500 – 1600 degree F, a lower temperature regime than other combustion systems. This temperature regime allows the addition of limestone. Limestone (CaCO3) is converted to CaO at about 1500 degree F, and CaO captures SO2 to form CaSO4, which is thermodynamically stable at 1500 – 1600 degree F. A removal efficiency of about 90% SO2 can be achieved with a Ca/S molar ratio of 2 to 2.5, which also varies from application to application, and depends on the sulfur content of the fuel, reactivity of the limestone, and the operation of the boiler.

9.3.2 Dry and Wet Scrubber

Post-combustion control for SO2 is accomplished by scrubbers. A calcium- or sodium-based reagent is typically used in a scrubber to absorb SO2. Sulfate or sulfite formed are either disposed, or further processed for commercial use. Scrubbers are commonly classified based on the process conditions (wet versus dry); the product utilization (throwaway versus saleable); and

[48] Assessment of Control Technology Options for BART-Eligible Sources – Steam Electric Boilers, Industrial Boilers, Cement Plants, and Paper and Pulp Facilities. Northeast States for Coordinated Air Use Management (NESCAUM) in partnership with the Mid-Atlantic Northeast Visibility Union (MANE-VU), March 2005.

the reagent utilization (once-through versus regenerable). Scrubbers are widely used in commercial applications such FCCUs (Chapter 3), utility/industrial boilers/heaters (Chapter 4), sulfur recovery and tail gas treatment (Chapter 5), sulfuric acid manufacturing (Chapter 6), container glass manufacturing (Chapter 7), and coke calcining (Chapter 8). Please refer to these chapters for further descriptions on this technology.

9.3.3 Costs and Cost Effectiveness Reported in Literature

Both wet and dry scrubbers are widely used in the U.S. for coal-fired utility boilers. The control efficiency, costs, and cost effectiveness reported abundantly in literature are provided in Table 9-3 and 9-4.

TABLE 9-~~3~~4
SOx Control Technology for Boilers ≥ 250 mmbtu/hr

Type	Type of Control	Control Efficiency	Cost Effectiveness
Coal Fired	Dry Scrubber	90% - 95%	\$1,622 - \$3,578
	Wet Scrubber	90% - 99%	\$1,881 - \$3,822
Oil Fired	Dry Scrubber	90% - 95%	\$1,841 - \$5,219
	Wet Scrubber	90% -99%	\$1,956 - \$5,215

Note: The data in this table are from *Best Available Retrofit Technology (BARCT) for Selected Non-Electric Generating Units (EGU) Source Categories*, MACTEC Federal Programs, Inc. developed for Lake Michigan Air Directors Consortium (LADCO), June 28, 2005.

TABLE 9– ~~3~~5
SOx Control Technology for Coal-Fired Boilers

Source	Type of Control	Control Efficiency	Capital Costs	Cost Effectiveness
Utility Boilers	Dry or Wet Scrubber	90%	\$180/kW for >600 MW units \$350/kW for 200-300 MW	\$200 - \$500 per ton SOx removed
Industrial Boilers	Dry Sorbent Injection	40%	\$8,600 - \$26,000 per mmbtu/hr	Not Estimated
	Spray Dryer Absorber	90%	Double of the costs for dry sorbent injection	\$400 - \$4000 per ton SOx removed
	Wet Scrubber	90%	50% higher than spray dryer absorber	Not Estimated

Reference: Assessment of Control Technology Options for BART-Eligible Sources – Steam Electric Boilers, Industrial Boilers, Cement Plants, and Paper and Pulp Facilities. Northeast States for Coordinated Air Use Management (NESCAUM) in partnership with the Mid-Atlantic Northeast Visibility Union (MANE-VU), March 2005

9.4 Control Technology for Cement Kilns

SOx emissions from a cement kiln are generated from 1) combustion of sulfur in fuel, and 2) oxidation of sulfides (e.g. pyrites) in the raw materials. Fuel switching, process alterations, dry and wet scrubbers are commercially available control technologies to reduce SOx emissions from a cement kiln. [49, 50] Table 9-4 presents the control efficiency for each technology and a brief description for each technology is presented below.

TABLE 9-46
Available Control Technology for Dry Cement Kilns

Type of Control	Control Efficiency
Fuel Switching and Process Alterations	0 – 100%
Spray Dryer Absorber	55% - 90%
Wet Scrubber	90% - 99.9%

Reference: *Assessment of Control Technology Options for BART-Eligible Sources – Steam Electric Boilers, Industrial Boilers, Cement Plants, and Paper and Pulp Facilities.* Northeast States for Coordinated Air Use Management (NESCAUM) in partnership with the Mid-Atlantic Northeast Visibility Union (MANE-VU), March 2005.

9.4.1 Fuel Switching

Cement kilns at CPCC use coal, coke, natural gas, oil and tires as combustion fuel. When the fuel sulfur levels in the primary fuels are high, switching to a lower sulfur content fuel is an appropriate strategy. However, this strategy may not be sufficient if the fuel sulfur content is much less than the sulfur content of the kiln feed (e.g. limestone). In this case, staged combustion with mid-kiln injection of a low-sulfur fuel, or high pressure air, may need to be considered. A post-combustion add-on control device may also be needed to further reduce SO2 emissions.

9.4.2 Process Control

The following process control can be used to reduce SOx emissions from the calciner kilns:

- It has been found that having sufficient oxygen to stabilize the alkali and calcium sulfate compounds formed in the burning zone of the rotary kiln minimizes SOx formation. The downside of this technique is that it can generate more NOx.

- It has been found that avoiding flame impingement in the burning zone, avoiding flame impingement on the clinker, or improving distribution of kiln feed to equalize temperatures in the kiln can minimize SO2 formation.

- It has been found that when alkali is in excess of sulfur, SO2 can be retained in clinker as alkali sulfate. In addition, reducing the amount of pyritic sulfur, or organic sulfur, in raw

[49] Assessment of Control Technology Options for BART-Eligible Sources – Steam Electric Boilers, Industrial Boilers, Cement Plants, and Paper and Pulp Facilities. Northeast States for Coordinated Air Use Management (NESCAUM) in partnership with the Mid-Atlantic Northeast Visibility Union (MANE-VU), March 2005.

[50] *Best Available Retrofit Technology (BARCT) for Selected Non-Electric Generating Units (EGU) Source Categories*, MACTEC Federal Programs, Inc. developed for Lake Michigan Air Directors Consortium (LADCO), June 28, 2005.

materials can lower the SOx emissions substantially. The downside of this technique is that the amount of alkali added, or the amount of pyretic sulfur removed, are often limited by the product specifications or market and economic factors.

9.4.3 Lime or Limestone Spray Dryer Absorber

Lime and limestone contains calcium, in the form of calcium carbonate ($CaCO_3$), which reacts with SO_2 and captures SO_2 to form of calcium sulfate ($CaSO_4$). Water is typically sprayed into the feed at the end of the kiln or introduced through dilution air at the air coolers. Two most common spray dryer absorbers are the RMC Pacific's Alkaline Slurry Injection System and the EnviroCare Microfine Lime System. The RMC Pacific uses a hydrated lime as scrubbing agent. The captured sulfur compounds are returned as a portion of the raw material feedstock to the roller mill, which results in no scrubber effluent or sludge disposal. The process has obtained efficiencies ranging from 55% to 65%. The EnviroCare uses water suspension of finely pulverized calcium hydroxide $Ca(OH)_2$ as scrubbing agent. Lime injection rate can be optimized through a feedback control loop from an SO_2 monitor which helps to reach a SOx removal efficiency of 90% or more.

9.4.4 Wet Scrubber

Wet scrubbing is a technique applicable to all types of cement kilns to remove SOx and particulate matter simultaneously. A wet scrubber is usually installed downstream of the baghouse and uses limestone as absorbent. The most common system is the DynaWare scrubber, developed by Monsanto, installed by Fuller Company, and used on several cement kilns in the U.S. Limestone slurry containing 20% limestone and 80% water is produced in a mixing tank and sprayed countercurrent to the gas flow, cools the gases, reacts with SO_2 to form calcium sulfite ($CaSO_3$), calcium sulfate ($CaSO_4$), and gypsum which in turn precipitate at the bottom of the absorbing tower and must be disposed of. A single-stage DynaWave scrubber in full-scale operation has a reported SO_2 removal efficiency of about 90%., and a multiple-staged unit may achieve 99.9% control efficiency. Please refer to Chapter 5 for further description on DynaWave scrubber.

9.4.5 Costs and Cost Effectiveness

Since wet and dry scrubbers are commonly used to further control SOx from the cement kilns, the costs and cost effectiveness of these technologies are abundantly available in literature, and are summarized in Table 9-5 and 9-6.

TABLE 9-~~5~~7
Costs for Control Technology for Dry Cement Kilns

Source	Clinker Capacity (tpy)	Spray Dryer		Wet Scrubber	
		Capital Cost ($/ton clinker)	Annual Operating Cost ($/ton clinker)	Capital Cost ($/ton clinker)	Annual Operating Cost ($/ton clinker)
Medium Kiln	600,000	$39.75	$14.79	$31.83	$17.21
Large Kiln	1,200,000	$23.17	$9.43	$20.42	$13.05

Note: (1) For comparison, CPCC Colton kiln #1 capacity is approximately 45 tons clinker per hour or 394,200 tons clinker per year based on a source test conducted in 2005, and an assumption that the kiln is operated 24 hours a day, 365 days a year. (2) The data in this table are from *Assessment of Control Technology Options for BART-Eligible Sources – Steam Electric Boilers, Industrial Boilers, Cement Plants, and Paper and Pulp Facilities,* Northeast States for Coordinated Air Use Management (NESCAUM) in partnership with the Mid-Atlantic Northeast Visibility Union (MANE-VU), March 2005.

TABLE 9-~~6~~8
Control Efficiency and Costs for Control Technology for Dry Cement Kilns

Source	Dry Scrubber		Wet Scrubber	
	Control Efficiency	Cost Effectiveness ($/ton SO2 removed)	Control Efficiency	Cost Effectiveness ($/ton SO2 removed)
Small Kiln	90%-95%	$2,000 - $6,917	90%-99.99%	$2,030 - $6,861
Medium Kiln	90%-95%	$1,925 - $7,379	90%-99.99%	$2,004 - $6,831
Large Kiln	90%-95%	$1,881 - $7,201	90%-99.99%	$1,990 - $6,816

Reference: *Best Available Retrofit Technology (BARCT) for Selected Non-Electric Generating Units (EGU) Source Categories*, MACTEC Federal Programs, Inc. developed for Lake Michigan Air Directors Consortium (LADCO), June 28, 2005.

9.5 BARCT Level and Emission Reductions

In September 2008, staff, WSPA and the refineries awarded a contract to ETS Inc. to conduct an independent feasibility and costs analysis of control technologies for cement kilns and coal-fired boiler. A summary of ~~the consultant~~ ETS, Inc.'s analysis is in Part 2 of the draft Staff Report. NEC indicated that they would recommend WGS as BARCT for both cement kilns and coal fired boilers but did not provided costs information. They indicated that WGS would be more cost-effective than the technologies that ETS recommended. However, if the technologies recommended by ETS were used, NEC would recommend adding contingencies to the ETS's estimates. The consultant~~'~~s' recommendations ~~is~~are ~~as follows:~~shown in Table 9-9.

TABLE 9-9
Initial Emission Reductions and Cost Effectiveness for Kilns & Coal Fired Boiler Estimated by ETS, Inc.

Equipment	BARCT Level	BARCT Emission Level	Emission Reductions	Cost Effectiveness by ETS
Kilns	95% control (≤2 ppmv)	0.03 lbs SO_x/ton clinker	0.25 tpd SO_x	$18.9 K per ton
Coal-Fired Boiler	95% control (≤5 ppmv)	---	0.36 tpd SO_x	$ 3.8 K per ton

Staff concurred with the consultants' recommendation for the coal-fired boiler, which is not in operation, at this time, and suggested the following BARCT level for the two cement kilns as shown in Table 9-10~~:~~.

TABLE 9-10
Revised Emission Reductions and Cost Effectiveness for Cement Kilns

Equipment	BARCT Level	BARCT Emission Level	Emission Reductions	Cost Effectiveness
Kilns	5 ppmv	0.04 lbs SO_x/ton clinker	0.25 tpd SO_x	$1~~8.~~9.3 k~~K~~ per ton per ETS $26.8 k per ton based on input from NEC

Chapter 10 – Continuous Emissions Monitoring System

Staff [51] conducted an inventory of the current Continuous Emissions Monitoring Systems (CEMS) used at the facilities to measure SOx from the seven affected categories of sources. The CEMS supplier and the SOx detection range, both low and high ranges, are presented in Table 10-1.

TABLE 10-1
Current CEMS System

Sources	Facility	CEMS Supplier	SO_2 Detection Range in ppm (High – Low)
FCCU	Refinery F	Rosemount	0-250
FCCU	Refinery C	Ametek	0-50
FCCU	Refinery A	Bovar	0-100
FCCU	Refinery D	Horiba	0-50 / 0-0.50 (diluted)
FCCU	Refinery E	API	0-50 / 0-200
FCCU	Refinery B	Teledyne	0-50 / 0-225
SRU/TG	Refinery F	Rosemount	0-500 / 0-2000
SRU/TG	Refinery C	Bovar	0-100
SRU/TG	Refinery A	Bovar	0-150 / 0-1000
SRU/TG	Refinery D	Rosemount	0-250
SRU/TG	Refinery E	API	0-20/0-50/0-1000
SRU/TG	Refinery B	Ametek	0-100 / 0-500
Sulfuric Acid	Facility Y	Bovar	0-1000
Sulfuric Acid	Facility X	Thermo Electron	0-200 / 0-1000 (actual); 0-4 / 0-20 (diluted)
Coke Calciner	BP	Rosemount	0-150
Cement	Cal-Portland Cement	Bovar/Ametek	0-500
Glass	Owens-Brockway	Thermo Electron	0-100 / 0-800

(Data provided by AQMD Source Testing Team)

To assure that there are systems capable of measuring low concentration levels of 5 ppmv – 40 ppmv SOx, staff conducted a research of market availability of CEMS for low level detection. For detection at the lower ranges for SO_2 (<10 ppm level), there are currently two main extractive methods for sampling the flue gas from a stack: dilution-extractive and extractive non-dilution.

10.1 Dilution-Extractive

This sample acquisition method allows for the sampling and detection of flue gas pollutants on a wet basis. This is convenient, since the mass emission rate is also determined on a wet basis. The extracted sample is diluted with clean air (typically in a 100:1 ratio) before analysis. The

[51] The author for Chapter 10 is Kevin Orellana.

analysis is performed with an ambient SO_2 analyzer, since the diluted pollutant concentration is near an ambient concentration level.

10.2 Extractive Non-Dilution

This sample acquisition method requires that the sample be clean and dry for measurement. Therefore, significant emphasis must be placed on particulate and moisture removal to ensure an accurate reading. This is often achieved by way of particulate filters and heated sample lines to prevent gas sample condensation. Furthermore, any remaining moisture in the sample is removed by way of a sample conditioning system. Usually, the technology employed involves refrigerated condensers, thermoelectric chillers, or gas permeation dryers. The cleaned, dry sample is then analyzed via an SO_2 gas analyzer.

For both sample acquisition methods, gas cleanup and sample conditioning is of foremost importance. For systems using dilution-extractive methods, the dilution air must be dry and free of contamination. For extractive non-dilution methods, the sample gas must be conditioned (free from particulate contamination, acid mist, ammonia, and moisture) since SO_2 is soluble in water.

The majority of the CEMS analyzers currently installed at SOx RECLAIM major sources employ extractive non-dilution sampling, and has the capability of monitoring in the 25ppm SO_2 full span range (FSR). As expected, some upgrades may have to be performed to the existing systems to achieve readability in the lower ppm SO_2 full span ranges. The first choice will be whether to install a dilution-extractive system with an ambient SO_2 analyzer as a replacement for an extractive non-dilution system. Both dilution-extractive and extractive non-dilution systems can be installed in SO_x RECLAIM source category equipment. However, some process-specific stack conditions may determine which type of system will work best at sample cleanup and analyte detection.

If sample dilution is determined as the best method for SO_2 detection, a completely new sampling system must be installed to measure pollutant gases on a wet basis approach. This will replace an existing extractive non-dilution system. The hardware required will consist of a dilution probe, sample lines, air clean up hardware, an ambient analyzer, plus integration hardware (cabinet, calibration hardware, programmable logic controller, and data acquisition system). The estimated cost for a new dilution-extractive system, including installation, is around $250,000. Since SO_2 will be detected on a wet basis, other criteria pollutants such as NO_x and CO may also be detected on a wet basis. New analyzers will have to be installed for these respective analytes in order to be sampled from the same dilution probe.

If a facility is currently operating an extractive non-dilution system and opts to continue criteria pollutant measurements on a dry basis, the two essential components required for an upgrade would be a new SO_2 gas analyzer and a gas conditioning system, such as a Nafion-based permeation drying system. Ametek Process Instruments, for example, manufactures an SO_2 gas analyzer whose minimum full scale is from 0-25 ppm SO_2. However, lower readings are possible by way of increasing the sample pressure and/or shifting to lower UV wavelengths for detection down to 0-10 ppm SO_2 FSR.

It is worth mentioning that if certain critical hardware components (e.g. probes, data acquisition systems, etc.) are near the end of their useful operating lives, a completely new extractive non-dilution system will need to be installed. This will consist of a probe, sample lines, gas conditioning system, analyzer, and integration hardware. The estimated cost for a new extractive non-dilution system, including installation, is also around $250,000.

However, if a facility that operates an extractive non-dilution system wants to only replace the SO_2 analyzer and install a stack–mounted, Nafion-based, permeation drying system, the cost is much less: around $35,000. The operator can continue to use its existing CEMS setup until the end of its useful life. The heated sample lines and condensation chillers can still be retained as a backup to the Nafion permeation drying system.

These above-mentioned systems have been in use at various SOx RECLAIM sources throughout the District. Each system uses industry-proven technology that achieves the required calibration results, analyte measurements, and valid Relative Accuracy Testing Audit (RATA) results.

Due to each individual facility's equipment setup, the CEMS shelter may or may not require relocation. The retrofits mentioned above are applicable to a scenario where the shelter is not being relocated. In this scenario, the sampling lines would be rerouted from the new SOx control equipment stack to the existing shelter.

However, the unique setup of a facility may necessitate the placement of the new control equipment at the current location of the CEMS shelter. If the facility elects to relocate its shelter, a concrete pad may need to be laid at the new shelter location and utility lines may have to be routed there. The facility may reuse and move the existing shelter and sample lines to the new shelter location, or purchase brand new equipment. A new air-purged, climate-controlled, Class 1 Division 2 shelter that can accommodate an analyzer rack costs about $250,000, and the facility may use general contractors or hire an engineering firm to design and manage the project, and the associated costs for these services may vary depending on the firm chosen.

TABLE 10-2
Future CEMS Capability

CEMS Supplier	Detection Range (ppm)	What needs to be done to upgrade existing setup?	Costs Per Unit
Horiba	0-0.05/0-0.1/0-0.2/0-0.5 (wet basis)	New sampling system (dilution probe, sample lines, dilution air cleanup, analyzer, integration hardware) + installation	$250,000
Ametek Process Instruments	0-25 (or lower, 0-10, with increased sample pressure and/or shorter UV wavelength detection, dry basis)	New sampling system (probe, heated sample lines, gas conditioning system, analyzer, integration hardware) + installation	$250,000
Perma Pure	for dry measurements	Nafion-based permeation drying system is directly mounted at the stack	$15,000
Ametek Process Instruments	0-25 (or lower, 0-10, with increased sample pressure and/or shorter UV wavelength detection, dry basis)	Direct SO_2 analyzer replacement at CEMS rack	$20,000

Chapter 11 – Water & Wastewater

11.1 ~~Water Demand~~District's Survey

11.1.1 Water Demand

A Survey Questionnaire shown in Appendix D was sent to the facilities in July 2009 to gather information on the water usage at the facilities. The facility's responses to this Survey Questionnaire were summarized in Table 11-1. ~~Based on the facility's responses and staff's collected information, staff concludes that while this project (consisting of installing/operating eleven wet gas scrubbers and two dry gas scrubbers at eleven major facilities to reduce 6.2 tons per day of SOx) would result in water demand that can be viewed as meaningful; can be met by current and future portable and recycled water suppliers; and the substantial air quality and health benefits of the project far outweigh the potential water impacts.~~ Staff's assessment of the information presented in Table 11-1 is below:

— Total water demand is below 1 million gallons per day. As shown in Table 11-1, the increase in total water demand (fresh and recycled water) for this project, consisting of 11 wet gas scrubbers and 2 dry gas scrubbers, is estimated about 364 million gallons per year (or 1 million gallons per day).[52, 53]

— Increase in total water demand. It should be noted that as shown in Table 11-1, eleven affected facilities currently use about 53 million gallons of water per day. The increase of 1 million gallons of total water per day demand for this project, while meaningful, represents a rather modest 2% increase over the current level of total water usage at the 11 facilities.[54]

[52] Information on water demand listed in the consultants' final report for SRU/TGTU's wet gas scrubbers were incorrect. Staff used information provided directly by the wet gas scrubbers' manufacturers as listed below. Tri-Mer information was based on the use of caustic as a scrubbing agent.~~:~~

Water Demand Information for SRU/TG's wet gas scrubbers		Refinery 6	Refinery 3	Refinery 2
Incorrect numbers listed in the consultants' final reports	MM gals/yr	614	158	342
Draft numbers listed in the consultants' draft final reports	MM gals/yr	75	19	25
Numbers provided by Tri-Mer	MM gals/yr	51	26	78
Numbers provided by DynaWave	MM gals/yr	31	11	47
Staff's Revised Numbers	MM gals/yr	51	26	78

[53] The six refineries alone would need about 264 million gallons water per year (0.7 million gallons per day) for this project. The six refineries currently consume 46 millions gals water per day. This project reflects a 1.5% increase in water demand for the refineries.

[54] Ten out of eleven facilities will have about 1% - 4% increase in water demand. Owens Brockway will experience a 44% increase in water demand. However, Owens Brockway has used wet gas scrubbers in the past before they switched to dry scrubbing technology and their water supplier (City of Vernon) indicated to staff that they can accommodate this increase of water demand.

- Water suppliers can meet additional demand. CEQA staff has consulted the water suppliers for all eleven affected facilities to ask if they can support the modest 2% increase in water demand of this project. The water suppliers indicated to staff that they can provide the amount of water increase.

- No cap on purchasing water. As shown in Table 11-1, the facilities reported that they have no cap in the amount of water (fresh or recycled) that they can purchase from the water suppliers. Some of the refineries indicated that they may have to pay an increase in water price in a near future because of the drought in California.[55] Since the water suppliers indicated that they can provide the water and there is no cap on the buyers, the 2% increase in water demand for this project can be met by the suppliers.

- Recycled water available at major refineries. As shown in Table 11-1, of the eleven facilities, three refineries (Refinery #2, 3, and 6) consume the largest amount of water, ranging from 3,000 – 4,500 million gallons per year. These refineries however already have access to recycled water. Currently, 50%-90% of the water used in these major refineries is recycled water. The suppliers of recycled water indicated that they are working in expanding their capacity to supply recycled water to the facilities in the basin and can supply the water demand increase for this project.

- Pumping capacity remained for in-house ground water wells. As shown in Table 11-1, seven of the eleven affected facilities have ground water wells. All seven facilities have unused pumping capacity. The remaining pumping capacity is well above the increase in water demand at the facility due to this project.

- Potable water demand is about 96,786 gallons per day. Based on the information in Table 11-1, two facilities (coke calciner and glass manufacturing) currently have no wells and no access to recycled water, and the increase in potable water demand from these two facilities will be about 96,786 gallons per day. The water suppliers indicated to CEQA staff that they can supply this increase in water demand.

~~11.2~~ 11.1.2 Wastewater

Based on the facility's responses shown in Table 10-2 and staff's collected information, staff believes the wastewater impacts from this project would be less than significant because of the following reasons:

- Small increase in discharge. As shown in Table 11-2, the project would generate about 2% increase in wastewater (range from <1% - 11%).

- Wastewater treatment & discharge capacity available. As shown in Table 11-2, the facilities have available discharge capacities. Their on-site wastewater treatment plan can handle the

[55] Regarding the price increase, a facility indicated that one of their facilities located in Northern California will install a wet gas scrubber as required by a U.S. EPA consent decree. The facility will pay premium price for the water usage above their cap, or conduct in-house program to monitor and conserve the water usage at their facility.

small increase. In addition, since the increase in discharge is less than 25%, the facilities need not to revise their discharge permit.

11.2 California Water Plan

The California Water Plan provides a framework for water managers, legislators, and the public to consider options and make decisions regarding California's water future. The Plan, which is updated every five years, presents basic data and information on California's water resources including water supply evaluations and assessments of agricultural, urban, and environmental water uses to quantify the gap between water supplies and uses. The Plan also identifies and evaluates existing and proposed statewide demand management and water supply projects to address the State's water needs. The California Department of Water Resources (DWR) just recently released the 2009 California Water Plan update in February 2010.[56]

The 2009 Plan focuses on strategies to use water efficiently, improve water reliability and water quality, and for the first time, integrate water resource management with flood management throughout the state. In addition, the Plan for the first time discussed the impacts of climate change and included the effects of climate change in estimating the water demand and supply for each of the ten hydrologic regions in California. The Plan includes 5 volumes: Volume 1 describes the current water conditions in California and challenges, presents the strategic plans for the state as well as for the 10 hydrologic regions, and identifies recommendations that will be incorporated statewide in the next couple years; Volume 2 describes 27 resource management strategies (e.g. reduce water demand, improve operational efficiency and transfers, increase water supply, improve water quality, practice resources stewardship, and improve flood management) that can be implemented in a mix and match fashion to help the 10 hydrologic regions to diversify their water portfolio and become more regionally self-sufficient; Volume 3 contains specific regional reports, and each regional report includes a water balance summary of water use and water supply for the region from 1998 through 2005, and scenario results that project the region's water needs through year 2050 with the use of three future scenarios (i.e. Current Trends, Slow and Strategic Growth, and Expansive Growth)[57] and 12 climate change scenarios; Volume 4 and Volume 5 contain references and technical information. For further information about the 2009 California Water Plan Update, please visit the website the California Department of Water Resources.[58]

[56] The 2009 California Water Plan Update, http://www.waterplan.water.ca.gov/cwpu2009/index.cfm,
http://www.waterplan.water.ca.gov/docs/cwpu2009/0310final/highlights_cwp2009_spread.pdf
http://www.waterplan.water.ca.gov/docs/cwpu2009/0310final/v3_southcoast_cwp2009.pdf
http://www.waterplan.water.ca.gov/docs/cwpu2009/0310final/v2c11_recycmuniwtr_cwp2009.pdf
http://www.waterplan.water.ca.gov/docs/cwpu2009/0310final/v2c03_urbwtruse_cwp2009.pdf

[57] In the "Current Trends" scenario, it was assumed that the existing trends in California will continue to 2050, the population increases to nearly 60 million people in California in 2050, affordable housing has drawn families to the interior valleys, and people take longer trips in distance and time. In the "Slow and Strategic Growth" scenario, it was assumed that there will be more efficient planning and development, population growth is slower and projected to increase to 45 million people, families live in compact urban development and commute less, Californian embraces water and energy conservation, and state government successfully implements and coordinates program to improve water quality. In the "Expansive Growth" scenario, it was assumed that the population will increase to 70 million people in 2050, Californian prefers low-density housing, some water and energy conservation was offered but at a slower rate than current trends.

[58] California Department Water Resources website - http://www.waterplan.water.ca.gov/

TABLE 11-1 – Water Demand Information

		Ref B	Ref A	Ref D	Ref C	Ref E	Ref F
FCCU	MM gals/yr	28	26			18	16
SRUs (Revised Numbers)	MM gals/yr	51	26	78			
Coke Calciner	MM gals/yr						
Sulfuric Acid Plant	MM gals/yr						
Glass	MM gals/yr						
Cement	MM gals/yr						
Boilers/Heaters (fuel gas)	MM gals/yr	4	3	5	6	5	0
Increase in Water Usage due to RECLAIM	**MM gals/yr**	**83**	**55**	**83**	**6**	**23**	**16**
	MM gals/day	**0.23**	**0.15**	**0.23**	**0.02**	**0.06**	**0.04**
Current Water Usage (Fresh and Recycled)	**MM gals/yr**	**4,468**	**3,792**	**3,150**	**3,154**	**2,102**	**639**
	MM gals/day	**12**	**10**	**9**	**9**	**6**	**2**
Fresh water	MM gals/yr	0.05 (<1%)	1,008 (26%)	0	12%	not provided	not provided
Cooling tower		1,682 (41%)	1,440 (38%)	1,100 (35%)	not provided	50%	not provided
Boiler feed		0.7 (16%)	1,344 (36%)	860 (27%)	not provided	25%	not provided
Others		2,785 (41%)	0	1.190 (38%)	not provided	25%	not provided
% Increase = (Increase in Usage / Current Usage)		**2%**	**1%**	**3%**	**0%**	**1%**	**3%**
Groundwater Wells		3	No well	6	2 active wells (1 at each site)	3 wells total at refinery 1 well at sulfur plant	No well
Max Allocation for Pumping	MM gals/yr	5,309 acre-ft/yr = 1,730 MM gals/yr = 3,291 gpm		2,570 acre-ft/yr = 837 MM gals/yr = 1,593 gpm	2,500 gpm	3,432 acre-ft/yr = 1,118 MM gals/yr = 2,128 gpm	
Current Rate of Pumping	MM gals/yr	1,727 acre-ft = 563 MM gals/yr = 1,071 gpm		526 MM gals/yr = 1,000 gpm	Between 600 gpm - 1,800 gpm	5,000 acre-ft/yr with lease agreements	
Unused Pumping Capacity?		Yes (67% remained)		Yes (37% remained)	Yes	Yes with lease agreements	
Recycled Water Usage	MM gals/yr	2,234 - 4,021	2,820	2,048	No	No	0
% Usage of Recycled Water		50% - 90%	74%	65%	0%	0%	0%
Water Supplier		CWS/WBMWD	WBMWD	WBMWD (65%), MWD (24%) and groundwater (11%)	CWS & LADWP	LADWP	LADWP (fresh water) & Air Products (small quality RO)
Maximum Purchase Limit?		No limit	No limit	No limit	No limit	No limit	No limit
CONCLUSION		**No limit from water supplier. Ground-water is available. Nominal increase of 2% can be met. (note 1)**	**No limit from water supplier. Nominal increase of 2% can be met. (note 2)**	**No limit from water supplier. Ground-water is available. Nominal increase of 2% can be met.**	**No limit from water supplier. Ground-water is available. Nominal increase of 2% can be met.**	**No limit from water supplier. Ground-water is available with lease agreement. Nominal increase of 2% can be met.**	**No limit from water supplier. Nominal increase of 2% can be met. (note 7)**

TABLE 11-1 – Water Demand Information (Cont.)

		BP Coke	Rhodia	OwensB (2 WGSs)	CPCC	Total
FCCU	MM gals/yr					88
SRUs (Revised Numbers)	MM gals/yr					155
Coke Calciner	MM gals/yr	15				15
Sulfuric Acid Plant	MM gals/yr		7			7
Glass	MM gals/yr			20		20
Cement	MM gals/yr				40	40
Boilers/Heaters (fuel gas)	MM gals/yr					23
Increase in Water Usage due to RECLAIM	**MM gals/yr**	**15**	**7**	**20**	**40**	**350**
	MM gals/day	**0.04**	**0.02**	**0.06**	**0.11**	**0.96**
Current Water Usage (Fresh and Recycled)	**MM gals/yr**	**394**	**266**	**46**	**1,200**	**19,211**
	MM gals/day	**1**	**1**	**0**	**3**	**53**
Fresh water	MM gals/yr			not provided		
Cooling tower		197 (50%)	226 (85%)	not provided	5%	
Boiler feed				not provided		
Others		197 (50%)	40 (15%)	not provided	95%	
% Increase = (Increase in Usage / Current Usage)		**4%**	**3%**	**44%**	**3%**	**1.8%**
Groundwater Wells		No well	1	No well	5	
Max Allocation for Pumping	MM gals/yr		521 acre-ft = 170 MM gals/yr		No limit	
Current Rate of Pumping	MM gals/yr		165 acre-ft = 54 MM gals/yr		1.9 MM gals/day	
Unused Pumping Capacity?			Yes. (68% remained)		No limit	
Recycled Water Usage	MM gals/yr	No	No	No	0	
% Usage of Recycled Water		0%	0%	0%	0%	
Water Supplier		Port of Long Beach	CWS	City of Vernon	Riverside Highland Water for potable an ind water from wells.	
Maximum Purchase Limit?		No limit	No limit	Not reported	No limit	
CONCLUSION		**No limit from water supplier. Nominal increase of 2% can be met. (note 8)**	**Ground water is available and no cap from water supplier. Nominal increase of 2% can be met. (note 9)**	**Wet gas scrubbers are past practice. Percent increase in water is meaningful but can be met.**	**No limit on groundwater pumping. Nominal increase of 2% can be met.**	**This project is expected to result in less than 2% increse in water demand. Adequate supply of water is available.**

TABLE 11-1 – Water Demand Information (Cont.)

Notes:

1. Information from survey responses was submitted by the facility in August 2009. The facility indicated that there was no cap on fresh or recycled water supply but the facility may have to pay a 21% increase in price of water in 2009, and may have been required to reduce water usage by 20%

2. Information from survey responses submitted by this facility on August 6, 2009. The facility indicated that there was no cap on water supply, however the WBMWD may mandate a 20% reduction in near future.

3. - 6. Reserved

7. Based on the Survey Responses submitted on August 8 and 13, 2009, the facility indicated that they do not have a cap on water supply, however LADWP must review any increase to assure that there is no physical constraint (e.g. piping, pump)

8. Based on the Survey Responses submitted on August 10, 2009, the facility indicated that they do not have limits on water supplied but they do expect to pay higher fees on discharged wastewater because the fees on discharged wastewater are based on total dissolved solids and COD

9. Rhodia water information from survey responses submitted by Rhodia on August 4, 2009.

CIWMB = California Integrated Waste Management Board
CWS = California Water Service
CRWQCB = California Regional Water Quality Control Board
DTSC = Department of Toxics Substance Control
LACBS = Los Angeles City Bureau of Sanitation
LACSD = Los Angeles County Sanitation District
LACDPW = Los Angeles County Department of Public Works
LADWP= Los Angeles Department Water & Power
MWD = Metropolitan Water District
NPDES = National Pollutant Discharge Elimination System
WBMWD= West Basin Municipal Water District

TABLE 11-2 – Wastewater Information

		Ref B	Ref A	Ref D	Ref C	Ref E	Ref F
FCCU	MM gals/yr	13	12		*20*	8	8
SRUs (Revised Numbers)	MM gals/yr	10	5	16			
Coke Calciner	MM gals/yr						
Sulfuric Acid Plant	MM gals/yr						
Glass	MM gals/yr						
Cement	MM gals/yr						
Boilers/Heaters (Fuel Gas)	MM gals/yr	3.18	2.16	5.27	6.09	4	0
Increase in Discharge	**MM gals/yr**	**27**	**19**	**21**	**6**	**12**	**8**
	MM gals/d	**0.07**	**0.05**	**0.06**	**0.02**	**0.03**	**0.02**
	gpm	**51**	**36**	**40**	**12**	**23**	**15**
Wastewater Treatment System?		Yes	Yes. Two systems. (note 2)	Yes	Yes	Yes	Yes - not currently active (note 6)
Wastewater Treatment Capacity		Capacity is limited to 8,000 gpm, normal 4,000 gpm.	1) Cap 5,000 gpm, avg 3,000 gpm. 2) Cap 2,000 gpm, avg 1,800 gpm	Cap is 3,500 gpm Normal rate is 3,000 gpm	There is a permit limit at one site which has a normal rate of 2,000 gpm. There is no limit	Cap is 6,000 gpm Normal rate is 2,215 gpm in dry & 2,260 gpm in wet	1.14 (note 6)
Regulator		LACSD	CRWQCB	LACSD	LACSD	LACSD	LACSD
Discharge Point		LACSD	Santa Monica Bay	LACSD	LACSD & LACBS	LACSD	LACSD & LACBS
Discharge Limit		Hydraulically limited to 8,000 gpm & limit in wet weather is 5,200 gpm	No limit	Limit in dry weather is 12,200 gpm & in wet weather is 7,500 gpm	Max limit is 5,000 gpm at one site, and there is no limit at the refinery	Max limit is 14.4 MM gals/day (10,000 gpm). (Note 5)	Limit by LACSD to 1.1 MM gals/day & limit in wet weather is 1000 gpm
Current Discharge		4,000 gpm	7 MM gals/day. 8.8 MM gals/day in dry weather, 27 MM gals/day in wet weather	3,000 gpm	2,000 gpm at one site and 1,400 gpm at the refinery.	2,215 gpm in dry weather and 2,260 gpm in wet weather	1.3 MM gals/day in 2008 (note 6)
Remaining Capacity = Discharge Limit - (Current Discharge + Increase)		3,649 gpm hydraulically & 1149 gpm in wet weather	No limit	In dry weather = 9,160 gpm & in wet weather = 4,460 gpm	No limit at the refinery. At the other site about 3,000 gpm	7,717 gpm	Already discharged 18% over the limit (note 6)
% Increase=(Increase / Discharge Limit)		<1%	---	<1%	0.2%	0.2%	1.8%
CONCLUSION		**Wastewater treatment & discharge capacity are available. No need to revise LACSD permit. (note 1)**	**Wastewater treatment and discharge capacity are available. (note 2)**	**Wastewater treatment and discharge capacity available.**	**Discharge capacity available. Less than significant impact.**	**Less than significant impact**	**No need to revise LACSD application Less than significant impact. (note 6)**

TABLE 11-2 – Wastewater Information (Cont.)

		BP Coke	Rhodia	OwensB	CPCC	Total
FCCU	MM gals/yr					61
SRUs (Revised Numbers)	MM gals/yr					31
Coke Calciner	MM gals/yr	6				6
Sulfuric Acid Plant	MM gals/yr		4			4
Glass	MM gals/yr			5		5
Cement	MM gals/yr				52	52
Boilers/Heaters (Fuel Gas)	MM gals/yr					
Increase in Discharge	**MM gals/yr**	**6**	**4**	**5**	**52**	**159**
	MM gals/d	**0.02**	**0.01**	**0.01**	**0.14**	**0.44**
	gpm	**11**	**8**	**10**	**99**	**302**
Wastewater Treatment System?		Yes. A basin for pH adjustment.	Yes. On-site tanks for neutralization.	Yes.	No wastewater treatment. Percolation ponds on site.	
Wastewater Treatment Capacity		0.18 MM gals/day (based on 125 gpm peak flow)	0.6 MM gals/day (425 gpm)	0.4 MM gals/day (250 gpm)		
Regulator		LACSD	LACSD & LACDPW	LACSD & City of Vernon	California Regional Water Control Board, Santa Ana	
Discharge Point		LACSD	LACSD	LACSD	On site	
Discharge Limit		0.18 MM gals/day (based on 125 gpm peak flow)	0.6 MM gals/day (425 gpm) as shown on LACSD permit	131.4 MM gals/yr (0.36 MM gals/day) (250 gpm)	No limit	
Current Discharge		0.09 MM gals/day (93,775 gpd or 65 gpm daily average)	Peak is 0.56 Mmgals /day (387 gpm), and average is 0.25 MM gals/day (175 gpm)	41.89 MM gals/yr (0.12 MM gals/day)	0.45 MM gals/day dust slurry to evaporation ponds & 1.05 MM gals/day of cooling water wastes to percolation ponds.	
Remaining Capacity = Discharge Limit - (Current Discharge + Increase)		0.07 MM gals/day (=0.18-0.09-0.02)	0.03 MM gals/day (=0.6-0.56-0.01)	84.5 MM gals/yr (0.23 MM gals/day)	No limit	
% Increase=(Increase / Discharge Limit)		11%	2%	4%	No limit	
CONCLUSION		**Discharge capacity available. Less than significant impact. (note 8)**	**Discharge capacity available. Peak flow must be carefully managed. (note 9)**	**Less than significant impacts**	**Less than significant impacts**	**Less than significant impacts**

TABLE 11-2 – Wastewater Information (Cont.)

Notes

1. This facility reported a maximum treated capacity of 8,000 gpm (12 million gals per day) and a normal treated rate of 4,000 gpm (6 million gals per day). SCAQMD data (e-mail from Hanh Le to Minh Pham on August 5, 2009) provided a slightly smaller discharge levels
2. This facility has two distinct wastewater treatment systems. The first system has primary treatment only. The second system has both primary and secondary treatment. The facility also has wastewater storage capacity to handle surges due to storms and upset
3. Reserved
4. For this refinery, see e-mail from Cynthia Carter to Minh Pham on August 5, 2009. Wilmington site has no maximum limit of discharge. LACSD indicated that they did not expect to see any significant impacts to their waste water treatment system
5. For this facility, see e-mail from Sawsan Andawis to Minh Pham on August 6, 2009. The facility reported that if they are over 25% baseload of waswater discharge limit, they will be subject to a large connection fee minimum of $7.8 MM & claimed that with a wet gas scrubber installation, they will exceed the 25% baseload, which is unlikely to occur.
6. From the Survey Responses submitted on August 8, 2009, the facility responded that they do not have a wastewater treatment facility, and currently send all wastewater to LACSD for treatment. Currently, the permit given by LACSD has a cap
7. Reserved
8. Based on the Survey Responses submitted on August 10, 2009, the facility indicated that "Additional scope and cost should have been included to reduce/offset/treat the quantity generated from this project....".
9. For Rhodia, based on the Survey Responses submitted on August 4, 2009, all wastewater is pumped into above ground agitated tanks and sodium hydoxide is added to elevate the pH above 6.0. The discharge limit is 0.6 MM gals per day max (425 gals/min).

CIWMB = California Integrated Waste Management Board
CWS = California Water Service
CRWQCB = California Regional Water Quality Control Board
DTSC = Department of Toxics Substance Control
LACBS = Los Angeles City Bureau of Sanitation
LACSD = Los Angeles County Sanitation District
LACDPW = Los Angeles County Department of Public Works
LADWP= Los Angeles Department Water & Power
MWD = Metropolitan Water District
NPDES = National Pollutant Discharge Elimination System
WBMWD= West Basin Municipal Water District

A big picture of the current water demand and use, the predicted water demand and use for the next 30 years, as well as the Best Management Practices (BMP) and the strategies to conserve water that the DWR recommends can be found in the 2009 California Water Plan Update. Staff focuses its research in the South Coast Hydrologic Region. The South Coast region is the California's most urbanized and populous region with the largest population of the state at almost 20 million. The South Coast region covers all of Orange County and portions of Ventura, Los Angeles, San Bernardino, Riverside and San Diego counties. The region has numerous sources of water supplies: imported water, surface water, groundwater, recycled water, and desalination. According to Metropolitan Water District of Southern California (MWD), half of the water supplied to the Southern California is from local supplies (e.g. groundwater wells. lakes) and the other half is imported water from Northern California via the State Water Projects (SWP) passing through the Sacramento-San Joaquin Delta (Delta), the Colorado River, and Owens Valley/Mono Basin.

The State Water Project (SWP) is an important source of water for the South Coast region. The SWP is managed by the California Department of Water Resources (DWR). There are about 6 major contractors for the SWP. These contractors take delivery and convey the suppliers to regional wholesalers and retailers. The MWD is one of the major contractors. The contract between MWD and DWR is approximately about 1.91 MAF per year, half of the total SWP.[59]

Another key imported water supply for the South Coast region is the Colorado River. The DWR is entitled to 4.4 MAF per year from the Colorado River, of which 3.8 MAF are assigned to agricultural users and the remaining to MWD. Within the last couple years, MWD routinely uses 1.2 MAF from the Colorado River because the agricultural users have not been using their full entitlement. MWD conveys the water through a 242-mile Colorado River Aqueduct to supply to the retailers in Southern California.

Another source of imported water is the water from Mono Basin and Owens Valley. Approximately 480,000 acre-feet per year of water is delivered by the LADWP through the Los Angeles Aqueduct to the City of Los Angeles. However, this amount varies from year to year due to fluctuating precipitation in the Sierra Nevada Mountains

Local surface water (e.g. Lake Casitas, Lake Piru, Castaic Lake, Lake Perris) plays an important part in the big picture of water supply to Southern California. More than 75 impound structures are used to capture runoff for direct use and groundwater recharge, operational and emergency storage, and food protection.

Groundwater production within the Metropolitan service area is estimated at 1.6 MAF per year. However, natural recharge is typically insufficient to maintain the groundwater basin water levels and current pumping levels due to the extent of impervious surfaces and the presence of clay soils. Many local water agencies must rely on artificial recharge (e.g. using recycled water). The Water Replenishment District of Southern California (WRD) has the mission to manage and protect the groundwater supply in the basin. In the past couple years, most basin adjudications

[59] 2009 California Water Plan Update, South Coast, Volume 3 Regional Report.

have resulted in either a reduction or no increase in the amount of groundwater that can be extracted.

Within MWD's service area, there are approximately 355,000 acre-feet of planned and permitted uses of recycled water supplies. Actual use is approximately 209,000 acre-feet, mainly in golf course, landscape, irrigation, industrial uses, construction applications, maintenance of seawater barriers, and groundwater recharge. The MWD projected a development of 500,000 acre-feet recycled water supplies by 2025. The use of recycled water by LADWP is projected to approximately 50,000 acre-feet per year by 2019.

Besides imported water, groundwater, and local surface waters, urban water conservation and desalination are also the sources of water supplies in the area. Local water agencies utilize a mixture of local and imported waters, and implement diverse water management strategies to meet the urban and agricultural demands. The total water use in the South Coast Hydrologic Region is reported to be approximately 4.8 MAF averaged from 1998-2005 period and about 5.2 MAF in 2005. In the 2009 California Water Plan Update, it is projected that the urban water demand will have a range of increase from 1.65 MAF in 2050 for the "Current Trends" scenario to 3.24 MAF with "Expansive Growth" scenario. The "Slow & Strategic Growth" scenario resulted in relative smaller increase in water demand of 0.145 MAF.

To meet the California's water challenges, Governor Schwarzenegger and state lawmakers have successfully crafted a plan that passed legislation and signed into law in November 2009. The plan is comprised of four policy bills (Senate Bills No. 1, 6, 7, 8) and $11.14 billion bond. Senate Bill No. 1 establishes the framework to provide a more reliable water supply to California and restore the Delta ecosystem. Senate Bill No. 6 requires, for the first time in California's history, that local agencies monitor the groundwater levels during both normal water years and drought conditions. Senate Bill No. 7 requires urban water agencies/suppliers to reduce the potable water consumption by 20% per capita by 2020, and Senate Bill No. 8 requires stronger accounting of the location and amounts of water being diverted from the Delta and appropriates existing bond funds to various activities to benefit the Delta ecosystem and secure the reliability of the state's water supply. In addition, the newly funded bond of $11.14 billion is approved by the Governor to fund drought relief, water supply reliability, Delta sustainability, statewide water system operational improvements, conservation and watershed protection, groundwater protection, and water recycling and water conservation programs. A summary of the four Senate Bills and bonds are provided in the 2009 California Water Plan Update.[60] The focus of the next section is to discuss the 20x2020 Water Conservation Plan which is the backbone of information for the Senate Bill 7 (SBX7 7) which calls for a 20% reduction of potable water per capita by 2020.

[60] The 2009 California Water Plan Update, 2009 Comprehensive Water Package – Special Session Policy Bills and Bond Summary. http://www.waterplan.water.ca.gov/docs/cwpu2009/0310final/v4c15a05_cwp2009.pdf.

11.3 20x2020 Water Conservation Plan

In February 2008, the Governor directed state agencies to develop a 20x2020 Water Conservation Plan that aims to reduce statewide per capita urban water use by 20 percent by the year 2020. In order to develop the 20x2020 Plan, an Agency Team was formed which consisted of state and federal agencies including the Department of Water Resources (DWR), State Water Resources Control Board (SWRCB), California Energy Commission (CEC), Department of Public Health (DPH), California Public Utilities Commission (CPUC), Air Resources Board (ARB), California Bay-Delta Authority (CBDA), and the US Bureau of Reclamation (USBR), with the contribution of the California Urban Water Conservation Council and water suppliers/purveyors and organizations through public workshop and meetings.

Several important facts of the scope of the 20x2020 Plan are summarized below:

1. **The Plan addresses only urban water use and conservation, not agricultural water use**;

2. **The Plan addresses only potable water use**. Urban potable water use includes all residential, commercial, institutional, and industrial users as well as non-revenue water. Non-potable recycled water was excluded while estimating baseline per capita urban water use to give credit to agencies that have promoted recycled water in the past. Additional use of recycled water will be a significant method by which regions can continue to offset baseline potable urban water demand to meet the 2020 goals;

3. **The plan does not address water supplied by customers for their own use.** The plan focuses on potable water supplied in municipal distribution systems and does not include quantities of self-supplied water (groundwater or surface water) in per capita use calculations.

4. **The plan recommends actions that will reduce per capita use, not total urban use, by 20 percent.** Since the population is always increased, total urban water use will never go down, therefore the plan aims at improving water supply reliability and water use efficiency.

5. **This plan does not set targets for individual water suppliers.** There are wide variations among water suppliers. This plan does not provide specific guidance to move from regional planning targets to supplier-specific targets. Water suppliers are to develop their own plan to meet the state goals.

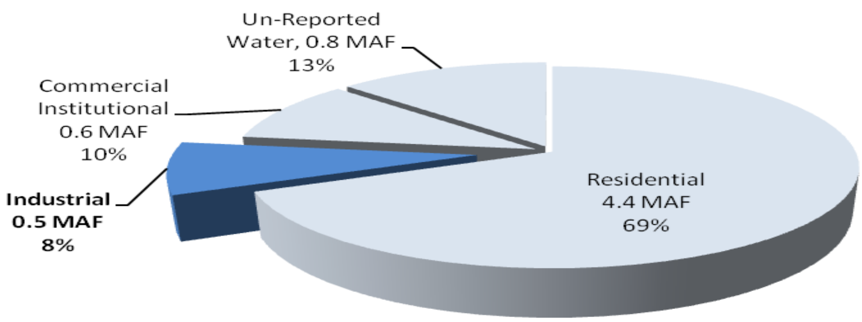
The 20x2020 plan is based on the 2005 baseline urban water use. As shown in Table 11-3, the total baseline for the South Coast region is 253 Gallons Per Capita Day, which approximately amounts to 6.37 million acre-feet per year using the projected 2020 population of 22.5 million in the South Coast Hydrologic Region. As shown in Table 11-3, the average water use for the industrial sector is approximately 8% of the total water use in the South Coast region.

TABLE 11-3
Urban Water Use Pattern in 2005 for South Coast Hydrologic Region

	Water Use
Residential (Single-and Multi-Family)	174 GPCD
Commercial and Institutional	25 GPCD
Industrial	21 GPCD
Un-Reported Water	33 GPCD
Total Baseline	**253 GPCD (6.37 MAF per year)**

Reference: Table 3 of the 20x2020 Water Conservation Plan, February 2010. Total projected 2020 population = 22.5 million. Therefore, 253 GPCD = (253 gallons per capita per day)(22.5 million)(365 days/year)(1 acre-ft/326,000 gals = 6.37 million acre-feet/year = 6.37 MAF/year)

TABLE 11-1
Urban Water Use in South Coast Hydrologic Region



After establishing the 2005 baseline, the Agency Team held numerous public meetings/workshops to establish the conservation targets and develop recommendations for future actions to achieve the targets.

Many urban water suppliers currently implement and enforce the 14 Best Management Practices. The Agency Team studied the results of the current actions and estimated future savings based on implementing current BMPs listed in Table 11-4. The Agency Team also evaluated new measures. Estimated savings for current and new measures are listed in Table 11-5.

The nine (9) Agency Team's recommended actions to achieve the Governor's statewide strategic goal of 20x2020 are listed below:

1. Establish a statewide conservation strategy
2. Reduce landscape irrigation demand
   - Require water-efficient landscapes at state-owned properties
   - Support the implementation and enforcement of landscape design and irrigation programs and the development of new landscape programs
   - Mandate the landscape irrigation Best Management Practices (BMP)

TABLE 11-4
List of Best Management Practices (BMPs)

BMP1	Water survey programs for residential customers
BMP2	Residential plumbing retrofit
BMP3	System water audits, leak detection and repair
BMP4	Metering with commodity rates for all new connections and retrofit of existing unmetered connections
BMP5	Large landscape conservation programs and incentives
BMP6	High efficiency clothes-washing machine financial incentive program
BMP7	Public information programs
BMP8	School education programs
BMP9	Conservation programs for commercial, industrial, institutional (CII)
BMP10	Wholesale agency assistance programs
BMP11	Retail conservation pricing
BMP12	Conservation coordinator
BMP13	Water waste prohibition
BMP14	Residential ultra-low-flush toilet (ULFT) replacement programs

TABLE 11-5
Summary of 2020 Savings from All Evaluated Measures for South Coast Region

	Water Saving (GPCD)
Efficiency Code Water Savings	
Residential – Indoor	4
Residential – Outdoor	0
Commercial, Institutional, Industrial (CII)	1
2020 Water Savings from Cost Effective Measures	
Residential – Indoor	2
Large Landscape	4
Commercial, Institutional, Industrial (CII),	7
Non-Revenue Water	4
Grant funded	1
Efficient Clothes Washers	2
Residential Flow Controllers	3
Total for Basic Measures	**24**
Accelerated coverage goals	7
Recycling	4
Water loss controls	4
Irrigation restrictions (2 days/week)	13
Miscellaneous measures	2
Total Additional Measures	**29**
Total Savings	**53**

Reference: Table 7 of the 20x2020 Water Conservation Plan, February 2010

3. Reduce water waste
   - Accelerate installation of water meters
   - Establish a state standard for water meter accuracy
   - Revise the water loss BMP to incorporate improved methodologies and accelerate coverage goals
4. Reinforce efficiency codes and related BMPs
   - Obtain authorization for state standards for high efficiency clothes washers
   - Support landscape irrigation equipment standards
   - Accelerate replacement of inefficient showerheads, toilets and urinals
   - Accelerate adoption of proven water saving technologies in new businesses
5. Provide financial incentives
   - Encourage or mandate conservation water pricing
   - Provide grants, loans, and rebates to wholesale and retail water suppliers and customers
   - Establish a public goods charge for water
   - Fund the installation of water meters
6. Implement statewide conservation public information and outreach campaign
7. Provide new or exercise existing enforcement mechanisms to facilitate water conservation
   - Require implementation of water conservation as a condition to receive state financial assistance
   - Take enforcement actions to prevent waste and unreasonable use of water
   - Provide additional enforcement tools for water suppliers
8. Investigate potential flexible implementation measures
   - Investigate requiring conservation offsets for water demand generated by new development
   - Investigate establishment of a cap-and-trade regime
9. Increase the use of recycled water and non-traditional sources of water

For comparison, the water savings from Table 11-5 are converted to million gallons of water savings per year and graphically shown in Figure 11-2. It should be noted that from Table 11-5, reducing water in irrigation to 2 days/week is the measure that would generate the most water savings. The two most important conservation measures which generate more than 50% of the conservation amount are conservation in irrigation and residential sector. The residential sector is expected to conserve more than the commercial, institutional, and industrial sector. Interestingly though is that the conservation from water loss controls is as significant as the conservation estimated for additional water recycling.

FIGURE 11-2
Comparison between Measures in the 20x2020 Plan

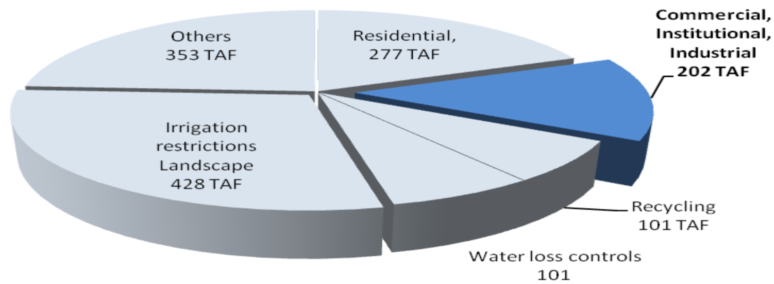


Table 11-7 shows a comparison of SOx RECLAIM total water and potable water demand to the water demand and savings of the statewide strategic plan of the South Coast Hydrologic Region. The total water demand for the proposed SOx RECLAIM project is about 0.02% of the total water usage in the South Coast Hydrologic Region. The increase in potable water demand of the proposed SOx RECLAIM project (for scenario that used wet gas scrubbers if future supplies of recycled water are available) is about 0.05% of the potable water savings estimated for the CII sector of the South Coast Hydrologic Region in 2020. Staff believes that the impacts on water demand and potable water demand is negligible based on the information in the 20x2020 Plan.

TABLE 11-7
Comparison of water demand for SOx RECLAIM Project
to the Statewide Strategic Plan of the South Coast Hydrologic Region

Total Water Usage — Baseline for South Coast region = 253 GPCD = 6.37 million acre-ft per year (MAF) — Future water demand for SOx RECLAIM = 1,000 acre-ft per year total water — Percentage = 1,000 / 6.37 million = **0.02 %**
Potable Water Savings — Savings estimated for Commercial, Institutional and Industrial sector for the South Coast region= 8 GPDC = 201,423 acre-ft per year — Potable water demand for scenario where wet gas scrubbers are used if future supplies of recycled water are available = 201,587 gals/day = 226 acre-ft per year — Percentage = 226 / 201,423 = **0.11%** — Potable water demand for scenario where DeSOx catalysts are used in FCCUs if future supplies of recycled water are available = 108,436 gals/day = 121 acre-ft per year — Percentage = 121 / 201,423 = **0.06%**

11.4 Urban Water Management Plans

The Urban Water Management Planning Act (Act) became effective on January 1, 1984, and requires that every urban water supplier that provides municipal and industrial water to more than 3,000 customers, or supplies more than 3,000 acre-feet per year (AFY) prepare and adopt an urban water management plan in accordance with prescribed requirements. The Act requires the water purveyors to provide information on water supply and demand in their service area, focus primarily on water supply reliability and water use efficiency measures and put strong emphasis on drought contingency planning and recycled water. With the passage of Senate Bills 610 and 221 in 2001, the Urban Water Management Plan (UWMP) becomes more important. With SB 610 and 221, the UWMP becomes a written verification and indication to whether or not the urban water suppliers can provide water to the people living in the area. The UWMP serves as the master plan for water supply and resources management, a guidance document for policy makers to secure a sustainable water supply, as well as an ultimate source of information to the citizens in the basin. Because of this magnitude of its importance, staff conducted a research on the UWMPs of the major suppliers in the basin to understand a big picture of the water supply and demand in the basin and to consciously and intelligently answer the following questions related to the SOx RECLIAM project:

- What is the current and future water supply and demand in the basin? What is the distribution of water use in the basin?
- What are the Best Management Practices (BMPs) recommended by the water experts to conserve water and secure water resources in California? What are their effectiveness and how much water that they can help to conserve? To what extend does recycled water use in the basin?
- How does the water demand increase for this SOx RECLAIM project measure up to the overall water use in the basin? Can the urban water suppliers supply this amount of increase? Can this amount of increase be mitigated?

The information on the water supply/demand and water reliability analysis in the UWMPs of the three major water suppliers in the basin, Los Angeles Department of Water & Power (LADWP), West Basin Municipal Water District (WBMWD), and Metropolitan Water District of Southern California (MWD) are presented below.

West Basin Municipal Water District (WBMWD)

The WBMWD is the sixth largest water district in the state of California, serving a population of about 915,000 in 17 cities. The WBMWD currently supplies an average of 220,000 acre-feet of water annually combined of groundwater, imported water and recycled water. WBMWD is currently the wholesale supplier of recycled water for three refineries in the SCAQMD – Refinery 2, 3, and 6, and will expand its service to deliver recycled water to the sulfuric acid plant in 2013.

The WBMWD actively produces and provides recycled water, supports a desalination project, and conducts numerous programs to promote water conservation. Some of its accomplishments are highlighted below:

- In 1992-1993, the WBMWD received state and federal funding to construct a world-class state of the art water treatment/recycling facility in the City of El Segundo named Edward C. Little Water Recycling Facility. The WBMWD is in the process of expanding the capacity of its facility to double the amount of recycled water produced in 2013. To promote the use of recycled water, the WBMWD advances funds for retrofit expenses which can be reimbursed through the water bills. The onsite plumbing retrofit costs are amortized over a 10 years period at WBMWD's cost of funds. Repayment can be made using the differential between potable and recycled water rates so that customers never pay more than potable rate. Once the loan is repaid, the rate reverts back to the current recycled rate

- The WBMWD incorporates all 14 Best Management Practices (BMPs) recommended by the California Urban Water Conservation Council (CUWCC) such as distributing water-saving showerheads and toilets, smart controllers, and conducting water recycling and water education workshops to increase public awareness about water conservation and help to increase water reliability within the region. As an example, providing $50 rebates for customers to replace/install Ultra-Low-Flush Toilet (ULFT) has saved from 44 acre-ft (1,544 toilets) to 123 acre-ft per year (4,234 toilets) in 5 years from 2000-2004. In addition, with the demand on the water supply continuing to increase, the WBMWD proactively pursues a demonstration-scale ocean-water desalination facility to explore the feasibility of large-scale ocean-water desalination for future supply.

The WBWMD is in the process of developing its 2010 Urban Water Management Plan (UWMP) which is due to the Department of Water Resources in 2011. As shown in its 2005 UWMP, the WBWMD is able to supply reliable water to meet the demands projected for 25 years from 2005 to 2030 in both single dry-year scenarios or multiple dry-year scenarios. The projected water demands, supplies, and surplus from the 2005 UWMP are presented in Table 11-8 for multiple dry-water years. The projected multiple dry-year scenarios were based on the low rainfall years in FY 2001-02, 2002-03, and 2003-04. **The WBMWD estimates that they will supply reliable water with a surplus varying from 7,800 acre-feet per year to 33,236 acre-feet per year for the next 30 years.**

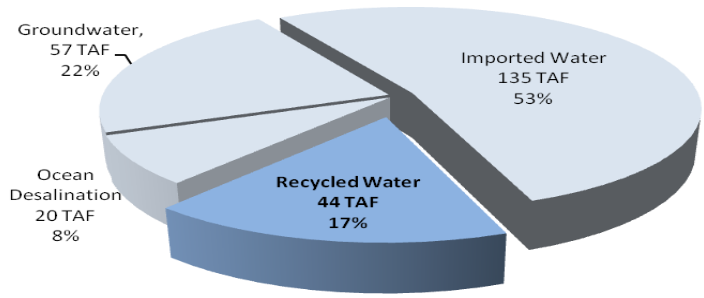
TABLE 11-8

Projected Water Demands and Supplies for Multiple Dry-Year Reliability [1, 2]

	Year 2010 (Acre-Feet)	**Year 2014 (Acre-Feet)**	**Year 2015 (Acre-Feet)**	**Year 2020 (Acre-Feet)**	**Year 2030 (Acre-Feet)**
Groundwater	56,797	56,797	56,797	56,797	56,797
Imported Water	135,334	130,940	135,334	135,334	135,334
Recycled Water	21,848	31,000	32,500	36,250	43,750
Ocean Desalination	0	20,000	20,000	20,000	20,000
Total Supply	**213,979**	**238,737**	**244,631**	**248,381**	**255,881**
Total Demand	**206,188**	**205,855**	**211,395**	**216,733**	**227,816**
Surplus	**7,791**	**32,882**	**33,236**	**31,648**	**28,065**

Note: 1) WBMWD 2005 Urban Water Management Plan, Chapter 4. 2) Supply reliability covers only water demand in municipal/industrial sectors and does not include replenishment.

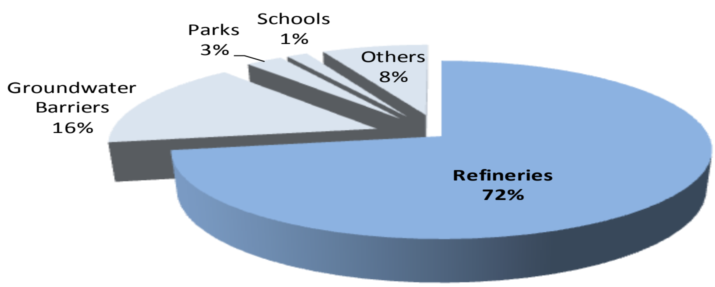
FIGURE 11-1
Projected Water Supplies for WBWMD Area (Year 2030)



Regarding recycled water, the WBWMD produces five different types of water quality from irrigation water (tertiary treated meeting California Title 22 regulation) to ultra pure Reverse Osmosis water for groundwater injection and industrial boiler feed as shown in Table 11-9.

The recycled water from WBMWD is used in various commercial, institutional and industrial operations, but mostly by refineries, with the distribution shown in Figure 11-2.

FIGURE 11-2
Distribution of Recycled Water Use for WBWMD Area



Regarding the WBMWD's water rates, the irrigation water is typically sold at a cost of $73 per acre-foot whereas ultra pure Reverse Osmosis Water is sold at a cost of $750 per acre-foot as shown in Table 11-1-B. Refinery A, B and D purchase a combination of nitrified water, one single pass pure RO water, and ultra pure RO water. **The consultants (ETS/AEC) have conservatively used a rate varying from $800 per acre-ft - $1,350 per acre-ft to estimate the annual water costs for SOx RECLAIM project accordingly to the information given to them by the refineries.**

The recycled water consumption by the three refineries located in the WBMWD's service areas is summarized in Table 11-10, side-by-side with the amount of recycled water that the refineries reported to staff, and the potential increase demand for this SOx RECLAIM project. The total recycled water purchased by the three refineries from WBMWD is about 18,945 acre-ft in 2008-09. The total recycled water usage reported to the District is about 21,785 acre-ft. The total increase due to SOx RECLAIM is about 678 acre-ft per year, approximately 3% increase over the baseline of 21,785 acre-ft.

As shown in its 2005 UWMP and the 2008-2009 Annual Report, the WBWMD has a potential to increase its supply of recycled water to 70,000 - 100,000 acre-feet, and will reach 31,000 acre-ft by 2014, 32,500 acre-ft by 2015, and 36,250 acre-ft by 2020. **Using the current distribution of 72% for refineries, staff projects approximately 22,320 acre-ft will be available to the three refineries in 2014, 23,400 acre-ft by 2015, and 26,100 acre-ft by 2020. The projected supply of recycled water is sufficient to cover the current demand of 21,785 acre-ft and the potential increase of 678 acre-ft for SOx RECLAIM project at these three refineries.** It is anticipated that the refineries will not implement all of the SOx RECLAIM measures at the same time in 2014, and they have extra underground pumping capacity available to balance the demand when in need.

TABLE 11-9
Type of Recycled Water & Rates [1]

Disinfected Tertiary Water	Treated secondary water from Hyperion that undergoes coagulation, flocculation, filtration and disinfection to meet the Title 22 standards. Tertiary water can be used for a wide variety of industrial and irrigation purposes where high-quality, non-potable water is needed.	$73 -$169 per acre-ft
Nitrified Water	Nitrified water is tertiary water that has been nitrified to remove ammonia, which can be corrosive to pipe material. This water is used in cooling towers.	$292 per acre-ft
Softened RO Water	Secondary treated water from Hyperion that has been treated with microfiltration, lime softeners and reverse osmosis. This water is used to replenish groundwater supplies. This water is superior to State and Federal drinking water standards.	$430 per acre-ft
Pure RO Water	Secondary treated water from Hyperion that has been treated with microfiltration and reverse osmosis. This water is used for low pressure boiler feed water for large scale industrial sites such as refineries.	$568 per acre-ft
Ultra Pure RO Water	Secondary treated water from Hyperion that has been treated with microfiltration and treated twice with reverse osmosis. This water is used for high pressure boiler feed water for large scale industrial sites such as refineries. This water is so pure that there is no mineral buildup and it can be used multiple times as boiler feed water before being discharged.	$750 per acre-ft

Note: 1) WBMWD 2005 Urban Water Management Plan, Chapter 8 – Water Recycling. 2) Rates from Chapter 7 of the WBMWD 2005 UWMP. 3) ETS/AEC has used a water rate of $2,794 per million gallons (or $910 per acre-ft, 20% higher than WBMWD's rate for the ultra pure RO water) in the cost analysis for SOx RECLAIM.

TABLE 11-10
Water Use and Potential Increase (Acre-Ft)

	WBWMD's 2008-09 Water Use Report [1, 2, 3]	Refinery's Data Reported to SCAQMD [4]	Potential Increase [5]
Refinery 3	8,587	8,650	169
Refinery 6	4,759	6,853	254
Refinery 2	5,599	6,282	255
Recycled Water Use by Refineries	18,945	21,785	678
Recycled Water Use by All Customers	23,588		
Capability of WBMWD	Projected: 31,000 by 2014; 32,500 by 2015; 36,250 by 2020; and 43,750 by 2030. Capability: 70,000 - 100,000		

Note: 1) Refineries purchase a combination of nitrification, pure single pass RO, and ultra pure double pass RO. 2) Refinery's recycled water use is about 90% - 95% of the total recycled water use by the city. 3) Refineries purchase 75% - 80% recycled water produced by WBWMD. The variation for past 10 years is shown. 4) SCAQMD's Survey. 5) Potential increase in water use by addition of wet gas scrubbers for FCCUs and SRUs, and by modification/addition of fuel gas treatment.

Los Angeles Department of Water & Power (LADWP)

On average, LADWP supplies 621,765 acre-feet of water per year (5-year average of supply from 1980-2009). The water distribution in the LADWP service area is shown in Figure 11-3. It should be noted that LADWP actively implements all 14 BMPs recommended by the California Urban Water Conservation Council (CUWCC) [61] and the DWR described in the 2009 California Water Plan. LADWP also implements many water conservation efforts (e.g. ultra-low-flush toilet retrofit program, indoor and outdoor conservation), public outreach, and school education program. As a result, the water usage in the city is the same as it was 20 years ago despite an increase in population of about 750,000 people. [62]

LADWP has a water shortage contingency plan with actions that can be undertaken in response to water supply shortages, including up to 50% reduction in water supply. Some of the actions identified in the water shortage contingency plan and currently implemented are: restricting landscape irrigation to two times a week, developing a large industrial customer incentive program that provides a monetary credit for all water conservation, irrigating public parks only

[61] The California Urban Water Conservation Council (CUWCC) is an organization formed in 1991 comprised of water suppliers and governmental agencies with a mission to promote water conservation in California. The CUWCC was instrumental in developing the "Memorandum of Understanding Regarding Urban Water Conservation in California (MOU) signed by numerous local water suppliers in California. The MOU identifies fourteen "Best Management Practices (BMPs) listed in Table 11-4 of this Staff Report, commits water suppliers to develop comprehensive conservation programs to implement the 14 BMPs, and establishes the CUWCC to monitor the implementation of the BMPs and to maintain and update the list of BMPs.

[62] City of Los Angeles Department of Water and Power, 2005 Urban Water Management Plan.

with recycled water, requiring recycled water to be used at commercial car washes and construction projects, and enforcing a tired billing structures to promote water use efficiently.[63]

The projected water demand/supply for the LADWP is presented in Figure 11-4 and Table 11-11 for the next 30 years. The projected water supply from municipal & industrial recycled water is only about 4% of the portfolio. It is interesting to note that LADWP expected to purchase more than 60% of its water from the Metropolitan Water District in 2030. **LADWP projected that they will have reliable water supply for the next 30 years for the area that they serve.**

FIGURE 11-3
Water Distribution in the LADWP Service Area

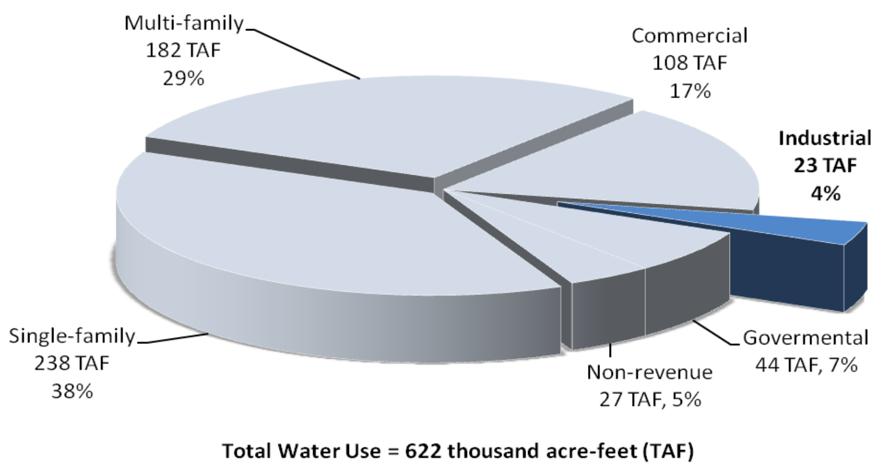
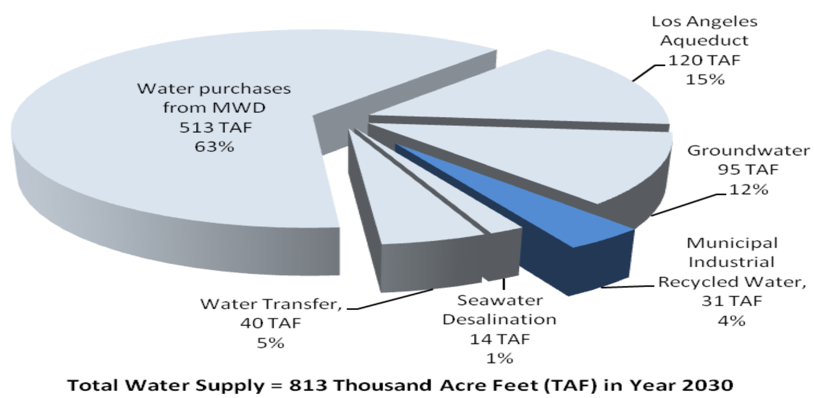


FIGURE 11-4
Water Supply in the LADWP Service Area (Year 2030)



[63] To promote the use of water efficiently, LADWP restructured its water rates to a two-tier structure in 1993 with a lower first tier rate for water used within a specified allotment, and a higher second tier rate for every billing unit that exceeds the first tier allotment. The water rates are also higher during shortage periods. For example, the Tier 1 rate for commercial and industrial customers is $1.21 per hundred cubic feet, and Tier 2 rate is $3.70 per hundred cubic feet during 10% shortage period. The Tier 1 rate remains at $1.21 for 15%, 20% and 25% shortage periods but Tier 2 rate increases to $4.44, $5.18 and $6.05 per hundred cubic feet in these shortage periods, respectively.

TABLE 11-11
LADWP Projected Water Demands and Supplies for Multiple Dry-Year Reliability [1, 2]

	Year 2010 (Acre-Feet)	Year 2015 (Acre-Feet)	Year 2020 (Acre-Feet)	Year 2030 (Acre-Feet)
Existing Supplies				
Los Angeles Aqueduct	120,000	120,300	120,300	120,300
Groundwater	95,000	95,000	95,000	95,000
Municipal & Industrial Recycled Water	1,950	1,950	1,950	1,950
Subtotal	**217,250**	**217,250**	**217,250**	**217,250**
Planned Supplies				
Municipal & Industrial Recycled Water	10,000	18,000	20,000	29,000
Seawater Desalination	0	13,500	13,500	13,500
Water Transfer	40,000	40,000	40,000	40,000
Subtotal	**50,000**	**71,500**	**73,500**	**82,500**
MWD Water Purchases	**449,750**	**450,250**	**475,250**	**513,250**
Total Supply	**717,000**	**739,000**	**766,000**	**813,000**
Total Demand	**717,000**	**739,000**	**766,000**	**813,000**

Note: 1) LADWP 2005 Urban Water Management Plan, Chapter 6. 2) Project with existing water conservation program.

Metropolitan Water District of Southern California (MWD)

The MWD is a public agency formed in the late 1920's. Its function is to manage the supply of water in Southern California. Its first function was building the Colorado River Aqueduct to convey water from the Colorado River in the early 1940s. In 1960, to meet increasing water demands, MWD contracted water supplies from the State Water Project (SWP) via the California Aqueduct, which is owned and operated by the DWR. The MWD currently receives imported water from two main sources: the Colorado River and the SWP. The MWD's service area covers a portion of Los Angeles, Orange, Riverside, San Bernardino, San Diego and Ventura counties. The MWD is a wholesaler and has no retail customers. The MWD distributes treated and untreated water directly to its 26 member agencies including 14 cities, 11 municipal water districts, and one county water authority (San Diego).

On daily average, the MWD delivers 6,023 AF. The record annual sales are 2.5 MAF in 1900. The projected sales for the next couple years for the commercial, institutional, industrial retail sector are estimated to be 1 MAF as shown in Table 11-12. Water is supplied at a unit price of $701 per acre-foot for treated water and $484 per acre-foot for untreated water. A balance of water supply and demand in Table 11-13 shows that MWD can provide reliable water under multiple dry year hydrologies. In addition, MWD has identified buffer supplies, including additional State Water Projects groundwater storage and transfer that could serve as a supply when additional water is needed.[64]

[64] The 2005 Regional Urban Water Management Plan – Metropolitan Water District of Southern California. November 2005. Metropolitan Water District website www.mwdh2o.com.

Just like the LADWP, the MWD has its water shortage contingency plan that outlines the necessary actions to be taken during water supply shortages including up to 50% reduction in its water supplies. The MWD also has a water surplus and drought management plan that outlines various resources to minimize the possibility of severe shortages by integrating the management of surplus and shortage into one plan. **Through effective management, the MWD indicated in its 2005 UWMP that it expected to be 100 percent reliable (with surplus supply) in meeting all demands in its service area.**

TABLE 11-12
MWD Projected Water Demands in Commercial. Industrial, Institutional Retail Sector

	Year 2010 (Acre-Feet)	Year 2020 (Acre-Feet)	Year 2030 (Acre-Feet)
Los Angeles	507,500	519,500	521,200
Orange	179,200	185,900	189,900
Riverside	64,400	78,500	93,000
San Bernardino	44,300	51,700	59,100
San Diego	167,200	171,400	174,500
Ventura	37,800	42,100	46,300
Total	**1,000,400**	**1,049,100**	**1,084,000**

Reference: Table A.1-10 of MWD's Urban Water Management Plan 2005.

TABLE 11-13
MWD Projected Water Demands and Supplies for Multiple Dry-Year Reliability

	Year 2010 (Acre-Feet)	Year 2015 (Acre-Feet)	Year 2020 (Acre-Feet)	Year 2030 (Acre-Feet)
Existing Supplies				
In-Basin Storage	514,000	518,000	502,000	470,000
California Aqueduct	912,000	912,000	912,000	912,000
Colorado River Aqueduct	722,000	699,000	699,000	699,000
Supplies Under Development				
In Basin Storage	78,000	103,000	103,000	103,000
California Aqueduct	330,000	215,000	299,000	299,000
Colorado River Aqueduct	95,000	460,000	400,000	400,000
Transfer to Other Agencies	0	(35,000)	(35,000)	(35,000)
Metropolitan Supply Capability	**2,651,000**	**2,872,000**	**2,880,000**	**2,848,000**
Firm Demands on Metropolitan	**2,392,000**	**2,302,000**	**2,309,000**	**2,585,000**
Potential Reserve and Replenishment Supplies	**259,000**	**502,000**	**473,000**	**155,000**

Reference: Table II-8 Multiple Dry Year Supply Capability and Projected Demands, The Regional Urban Water Management Plan of Metropolitan Water District of Southern California, November 2005.

11.5 Conclusion

In summary, the information and analysis above shows the following:

- The water demand increase due to this SOx RECLAIM project (consisting of installing/operating eleven wet gas scrubbers and two dry gas scrubbers at eleven major facilities to reduce 6.2 tons per day of SOx) is negligible at 1,000 acre-feet per year compared to the water use of 6.37 million acre-feet per year for the South Coast Hydrologic region. It represents 0.02% increase over the current water usage baseline.

- The potable water demands of this SOx RECLAIM project are approximately from 121 acre-ft per year to 226 acre-ft per year which represent about 0.06% - 0.11% of the potable water savings of 200 thousand acre-feet per year estimated for the South Coast Hydrologic region.

- Table 11-4 provides a comparison of the water demand for SOx RECLAIM project with the water use/demand in California, South Coast Hydrologic region and other local water suppliers. The purpose of Table 11-14 is to put the water demand of SOx RECLAIM project into the perspective of others.

TABLE 11-14
Comparison of Water Supplies and Demands

	Water Use (Acre-Feet Per Year)
California (Year 2005 Urban Use)	7,900,000
South Coast Hydrologic Region (Year 2005 Urban Use)	6,370,000
Projected increase for the South Coast (Year 2050)	1,650,000
MWD's contract with DWR (State Water Project)	1,910,000
MWD's entitlement from Colorado River through DWR	1,200,000
MWD's projected supplies (Year 2030)	2,848,000
MWD's projected supplies for commercial, industrial, institutional sector (Year 2030)	1,084,000
Groundwater production in MWD's service area	1,600,000
LADWP – All sectors	621,765
LADWP – Industrial sector	23,384
Recycled water supplied by MWD	355,000
Projected total water supplied by West Basin (Year 2030)	255,881
Projected recycled water supplied by West Basin (Year 2030)	43,750
Baseline for 11 Major SOx RECLAIM Facilities	**57,798**
Project Increase for SOx RECLAIM	**1,000**

- The water suppliers can reliably supply water, including recycled water, for the next 30 years and meet the nominal increase in water demand from this project based on the predicted water supply/demand shown in the 2005 UWMPs.

- The average water use in industrial sector is only about 8% for the South Coast Hydrologic Region, 4% for the LADWP service area, and 25% for the MWD. The Best Management Practices for conserving water focus in the areas that can significantly reduce water such as irrigation and residential sector. The Agency Team of the 20x2020 Plan estimated that water savings from the Commercial, Institutional, Industrial sector only contributes approximately 15% to the overall water savings required to meet the 20% reduction by 2020 asked for the Governor. Increased use of recycled water, if available, is a BMP that can be used to mitigate increase in water demand from this project.

- The consultants have appropriately used a rate varying from $800 per acre-ft to $1,350 per acre-ft to estimate the annual water costs for SOx RECLAIM project accordingly to the information provided to them by the refineries.

While this project would result in water demand that can be viewed as meaningful, the proposal can be met by current and future portable and recycled water suppliers. The substantial air quality and health benefits of the project far outweigh the potential water impacts. However, in the spirit of carrying out abundance of caution in response to the drought affecting California, CEQA staff made the determination that the SOx RECLAIM project would be considered significant if recycled water is not available. Please refer to the August 18, 2010 Draft Program Environmental Assessment document for further information.

Chapter 12 – Costs & Cost Effectiveness Analysis

12.1 Scenario Analysis

Staff conducted the following four scenario analysis to estimate overall emission reductions for the project, costs, cost effectiveness, control factors, and RTC reductions.

Scenario 1 – Most Stringent

- 1 ppmv for FCCUs (98% control),
- 1 ppmv for SRU/TGTUs
- Tier I level for boilers/heaters (40 ppmv, or to appropriate sensible levels)
- 5 ppmv for coke calciner
- 5 ppmv for sulfuric acid
- 1 - 2 ppmv (99% control) for glass furnace
- 1 - 2 ppmv (99% control) for cement plant

Scenario 2 – Consultants' Recommendations

- 5 ppmv for FCCUs,
- 5 ppmv for SRU/TGTUs
- Tier I level for boilers/heaters (40 ppmv, or to appropriate sensible levels)
- 10 ppmv for coke calciner
- 10 ppmv for sulfuric acid
- 1 – 2 ppmv (99% control) for glass furnace
- 1 - 2 ppmv (99% control) for cement plant

Scenario 3A – Staff's Recommendations on January 8, 2010

The controls with cost effectiveness less than \$50K per ton at the following proposed BARCT levels:

- 5 ppmv for FCCUs
- 5 ppmv for SRU/TGTUs
- Tier I level for boilers/heaters (40 ppmv)
- 10 ppmv for coke calciner
- 10 ppmv for sulfuric acid
- 5 ppmv for glass furnace
- 5 ppmv for cement plant

Scenario 3B – Alternative to Staff's Recommendation in Scenario 3A.

The controls with cost effectiveness less than \$50K per ton at the following proposed BARCT levels:

- 7 ppmv for FCCUs
- 10 ppmv for SRU/TGTUs, coke calciner, glass, cement
- Tier I level for boilers/heaters (40 ppmv)

~~Scenario 4 – Minimum Requirements for 3 tons per day reduction~~. The results were presented in Table 12-1 using the information provided by ETS/AEC and NEXIDEA. In addition, staff added two more scenarios in the analysis, Scenario 4 and 5. In Scenario 4, there would be no

BARCT for SRU/TGs and Scenario 5 is to meet the minimum requirements in the 2007 AQMP. Please refer to Section 12.3 for further information.

After January 8, 2010 Governing Board meeting, staff received feedback from WSPA and the refineries, and as a result, Scenario 3A was modified to not include costs associated with the modifications for boilers/heaters to meet the existing Tier 1 BARCT at 40 ppmv. In addition, modification to the cost effectiveness was made to exclude any incurred costs and emission reductions from projects that have already been completed. The results in Table 12-1 for Scenario 3A are revised to:

Scenario 3A – Staff's Current Recommendation

Present Worth Values = \$745 million – \$116 million (for boilers/heaters) = \$630 million

Emission reductions = 6.20 – 0.85 (for boilers/heaters) – 1.00 (reductions that already been achieved) = 4.36 tons per day

Weighted average cost effectiveness = \$15,845 per ton

12.2 Cost-Effectiveness Analysis Using NEC's Estimates

In March 2010, staff contracted with NEC, Inc. to conduct a refinery walkthrough in an effort to resolve any pending issues not addressed by the previous consultants and to review the feasibility and costs estimated by ETS/AEC and NEXIDEA. NEC provided a review of the capital costs and annual operating costs only, and recommended that staff re-estimate the cost effectiveness of the project. Staff's estimates using NEC's recommendations are summarized below.

Fluid Catalytic Cracking Units

NEC's estimates of capital costs for five new wet gas scrubbers at the refineries were:

- \$60,823,000 for Refinery #1 (approximately 1% higher than ETS's estimate)
- \$94,281,000 for Refinery #2 (approximately 6.6% lower than ETS's estimate)
- \$89,953,000 for Refinery #3 (approximately 16% higher than ETS's estimate since NEC included \$1.88 million for additional PM10 control. If NEC did not include the \$1.88 million for additional PM10 control which would not be required under the proposed rule, staff estimated the total capital costs for Refinery #3 would be \$83,028,000 by using NEC's approach, NEC's multipliers for vendor bias factor, and equipment budget factor, and NEC's estimates for piping, ductwork, knife gate valves, insulation etc.)
- \$66,670,000 for Refinery #4 (approximately 1.4% higher than ETS's estimate)
- \$83,164,000 for Refinery #6 (approximately 4.4% lower than ETS's estimate)

NEC recommended that the maintenance costs should be about 0.6% of the capital costs. Turnaround occurs every 5 years, and during this period, NEC estimated that the maintenance costs should be double the regular maintenance costs. Staff adjusted the maintenance costs in ETS/AEC's analyses to reflect NEC's recommendation. An example of staff's approach is provided below:

Example for Refinery #1:
Maintenance costs = (Capital costs by NEC)(0.6/100) = ($60,823,000)(0.6/100) = $364,938
Annual costs = $1,050,951 (by ETS) - 156,000 (maintenance costs estimated by ETS) + $364,938 (maintenance costs recommended by NEC) = $1,259,889

Staff then estimated the Present Worth Values (PWV) and Cost Effectiveness (CE) using NEC's capital costs and annual operating costs. An example is given below for Refinery #1. The PWV and CE for the 5 refineries are summarized in Table 12-2.

PWV = Capital Costs + (15.62)(Annual Operating Costs) – (0.35)(Salvage Value)[65] + (2.4)(Maintenance Costs Every 5 Years) = $60,823,000 + (15.62)(1,259,889) – (0.35)(250,000) + (2.4)(364,938) = $81,290,817

CE = ($81,290,817)/((211.82 tpy)(25 years)) = $15,351 per ton

TABLE 12-2
Cost Effectiveness of Wet Gas Scrubbers for FCCUs using NEC's Data

	Ref #1	**Ref #2**	**Ref #3 (note)**	**Ref #4**	**Ref#6**
Capital Costs ($)	60,823,000	94,281,000	83,028, 000 – 89,953,000	66,670,000	83,164,000
Annual Operating Costs ($)	1,259,889	$2,492,288	1,457,776 – 1,499,326	1,058,782	1,603,872
Present Worth Values ($)	81,290,817	126,253,530	106,906,571 – 114,580,302	84,080,722	109,333,879
Cost Effectiveness ($/ton)	15,351	72,393	41,292 – 44,256	45,121	12,783

Note: the low numbers in the range are for WGS without additional PM10 control capability, and the high numbers are for WGS with additional PM10 control capability

Sulfur Recovery/Tail Gas Units

NEC's estimates of capital costs for WGSs were:

- $49,100,000 for Refinery #2 (approximately 29% higher than ETS's estimate)
- $58,210,000 for Refinery #6 (approximately 13% higher than ETS's estimate)

NEC's indicated that the oxidation catalyst technology has not yet been proven in practice. NEC recommended wet gas scrubber as BARCT for SRU/TGs. However, if the oxidation catalyst technology was selected, the capital costs would increase by a factor of at least 5 versus ETS/AEC's estimates, or $63,416,089 for Refinery #3. NEC estimated that the maintenance costs should be about 0.6% of the capital costs. Turnaround occurs every 5 years, and the maintenance costs should be double the regular maintenance costs in these years. Staff adjusted the maintenance and annual operating costs in ETS/AEC's analyses to reflect NEC's recommendation. An example of staff's approach is provided below.

[65] Salvage value is value of the control equipment at the end of its useful life (after 25 years).

TABLE 12-1 – Costs & Cost Effectiveness

Equipment	**Fluid Catalytic Cracking Units**					
Facility	**Refinery 1**	**Refinery 2**	**Refinery 3**	**Refinery 4**	**Refinery 5**	**Refinery 6**
Control Technology /Vendor	WGS - BELCO					
Present Worth Value ($ million)	76	133	95	78		110
Scenario 1 - most stringent	**98% for 6 refineries**					
Performance Level	98%	98%	98%	98%	*98%*	98%
Emission Reductions (tpd)	0.60	0.30	0.35	0.24	*0.94*	1.01
Cost Effectiveness ($/ton)	14,000	48,000	29,500	35,200	*10,700*	11,900
BARCT	0.36 lbs/Mbarrels					
BARCT/Start EF	0.01 (=0.36/52.06)					
Scenario 2 - consultants	**5 ppmv for 6 ref - 5 new wet scrubbers and 1 existing wet scrubber**					
Performance Level	5 ppmv	5 ppmv	5 ppmv	5 ppmv	5 ppmv	5 ppmv
Emission Reductions (tpd)	0.58	0.19	0.28	0.20	0.87	0.94
Cost Effectiveness ($/ton)	14,437	76,211	36,636	42,103	11,600	12,849
BARCT			2.29	lbs/Mbarrels		
BARCT/Start EF			0.04	(=2.29/52.06)		
Scenario 3A - staff's	**5 ppmv for 5 ref - 4 new wet scrubbers, 1 existing wet scrubber**					
Performance Level	5 ppmv	5 ppmv	5 ppmv	5 ppmv	5 ppmv	5 ppmv
Emission Reductions (tpd)	0.58		0.28	0.20	0.87	0.94
Cost Effectiveness ($/ton)	14,437	>50,000	36,636	42,103	11,600	12,849
BARCT			3.25	lbs/Mbarrels		
BARCT/Start EF			0.06	(=3.25/52.06)		
Scenario 3B - Alternative	**7 ppmv with DeSOx catalysts**					
Performance Level	7 ppmv	7 ppmv	7 ppmv	7 ppmv	7 ppmv	7 ppmv
Emission Reductions (tpd)	0.57	0.14	0.25	0.19	0.83	0.90
Cost Effectiveness ($/ton)	18,941	18,941	18,941	18,941	18,941	18,941
BARCT			3.23	lbs/Mbarrels		
BARCT/Start EF			0.06	(=3.23/52.06)		

TABLE 12-1 (Continue)

Equipment	**Sulfur Recovery Units/Tail Gas**					
Facility	**Refinery 1**	**Refinery 2**	**Refinery 3**	**Refinery 4**	**Refinery 5**	**Refinery 6**
Control Technology /Vendor	Emerachem	WGS-TriMer	Emerachem for 2 SRUs & Tri-Mer	Emerachem	WGS-TriMer	WGS-TriMer
Present Worth Value ($ million)	26	60	17	19	64	97
Scenario 1 - most stringent	**98% for 6 refineries**					
Performance Level						
Emission Reductions (tpd)	0.13	0.20	0.15	0.04	0.07	0.31
Cost Effectiveness ($/ton)	22,410	32,900	12,881	54,686	95,800	34,300
BARCT			2.92	lbs/hr		
BARCT/Start EF			0.35	(=2.92/8.39)		
Scenario 2 - consultants	**5 ppmv for 6 refineries. 3 with Emerachem. 5 new wet scrubbers**					
Performance Level	5 ppmv	5 ppmv	5 ppmv	5 ppmv	5 ppmv	5 ppmv
Emission Reductions (tpd)	0.13	0.17	0.15	0.04	0.06	0.29
Cost Effectiveness ($/ton)	22,409	39,000	12,880	54,705	123,169	36,359
BARCT			3.89	lbs/hr		
BARCT/Start EF			0.46	(=3.89/8.39)		
Scenario 3A - staff's	**5 ppmv for 4 refineries. 1 already met reduction. 1 with Emerachem. 3 new wet scrubbers**					
Performance Level	Already met	1WGS 5 ppmv	Emera 5 ppmv			2WGS 5 ppmv
Emission Reductions (tpd)	0.13	0.17	0.15			0.29
Cost Effectiveness ($/ton)	n/a	39,000	12,880	>50,000	>50,000	36,359
BARCT			5.28	lbs/hr		
BARCT/Start EF			0.63	(=5.28/8.39)		
Scenario 3B - Alternative	**10 ppmv for 3 refineries. 1 already met reduction. 0 Emerachem. 4 new wet scrubbers.**					
Performance Level	Already met	1WGS 10ppmv	1WGS 10 ppmv			2WGS 10 ppmv
Emission Reductions (tpd)	0.13	0.13	0.11			0.27
Cost Effectiveness ($/ton)	n/a	48,606	34,695	>50,000	>50,000	39,147
BARCT			6.39	lbs/hr		
BARCT/Start EF			0.76	(=6.39/8.39)		

TABLE 121-1 (Continue)

Equipment	Refinery Boilers/Heaters					
Facility	Refinery 1	Refinery 2	Refinery 3	Refinery 4	Refinery 5	Refinery 6
Control Technology /Vendor	FGT	FGT	FGT	FGT	FGT	FGT
Present Worth Value ($ million)	1.4	20	15	16	64	21
Scenario 1 - most stringent	**To Tier I level**					
Performance Level						
Emission Reductions (tpd)	0.06	0.07	0.04	0.35	0.33	0.04
Cost Effectiveness ($/ton)	2,395	30,948	46,906	4,903	21,071	57,416
BARCT	40 ppmv = 6.76 lbs/mmscft					
BARCT/Start EF	0.2 (=6.76/33)					
Scenario 2 - consultants	**To Tier I level**					
Performance Level						
Emission Reductions (tpd)	0.06	0.07	0.04	0.35	0.33	0.04
Cost Effectiveness ($/ton)	2,395	30,948	46,906	4,903	21,071	57,416
BARCT	40 ppmv = 6.76 lbs/mmscft					
BARCT/Start EF	0.2 (=6.76/33)					
Scenario 3A - staff's	**To Tier I level**					
Performance Level						
Emission Reductions (tpd)	0.06	0.07	0.04	0.35	0.33	
Cost Effectiveness ($/ton)	2,395	30,948	46,906	4,903	21,071	>50,000
BARCT	40 ppmv = 6.76 lbs/mmscft					
BARCT/Start EF	0.2 (=6.76/33)					
Scenario 3B - Alternative	**To Tier I level**					
Performance Level						
Emission Reductions (tpd)	0.06	0.07	0.04	0.35	0.33	
Cost Effectiveness ($/ton)	2,395	30,948	46,906	4,903	21,071	>50,000
BARCT	40 ppmv = 6.76 lbs/mmscft					
BARCT/Start EF	0.2 (=6.76/33)					

TABLE 12-1 (Continue)

Equipment	**Coke Calciner**	**Sulfuric Acid Plant**		
Facility	**Fac C**	**Fac A**	**Fac A**	**Fac B**
Control Technology /Vendor	WGS-BELCO	Equip Mod-Cansolv	WGS-BELCO	WGS-BELCO
Present Worth Value ($ million)	25.3	1.7	8.0	17.3
Scenario 1 - most stringent	**5 ppmv-1 wet scrubber**	**5 ppmv**		
Performance Level	5 ppmv (90%)	not applicable	5 ppmv (>95%)	5 ppmv (>95%)
Emission Reductions (tpd)	0.32		0.04	1.1
Cost Effectiveness ($/ton)	8,642		17,596	1,594
BARCT	0.03 lbs/ton coke		0.07 lbs/ton acid	
BARCT/Start EF	0.01 (=0.03/2.47)		0.02 (=0.07/3.93)	
Scenario 2 - consultants	**10 ppmv-1 wet scrubber**	**10 ppmv**		
Performance Level	10 ppmv	10 ppmv	not applicable	10 ppmv
Emission Reductions (tpd)	0.28	0.033		1
Cost Effectiveness ($/ton)	9,902	5,556		1,896
BARCT	0.11 lbs/ton coke	0.14 lbs/ton acid		0.14 lbs/ton acid
BARCT/Start EF	0.05 (=0.11/2.47)	0.04 (=0.14/3.93)		0.04 (=0.14/3.93)
Scenario 3A - staff's	**10 ppmv-1 wet scrubber**	**10ppmv - 1 WGS, 1 modification**		
Performance Level	10 ppmv	modification to 10 ppmv	not applicable	1WGS 10 ppmv
Emission Reductions (tpd)	0.28	0.033		1
Cost Effectiveness ($/ton)	9,902	5,556		1,896
BARCT	0.11 lbs/ton coke	0.14 lbs/ton acid		0.14 lbs/ton acid
BARCT/Start EF	0.05 (=0.11/2.47)	0.04 (=0.14/3.93)		0.04 (=0.14/3.93)
Scenario 3B - Alternative	**10 ppmv-1 wet scrubber**	**10 ppmv**		
Performance Level	10 ppmv (80%)	modification to 10 ppmv	not applicable	1WGS 10 ppmv
Emission Reductions (tpd)	0.28	0.033		1
Cost Effectiveness ($/ton)	9,902	5,556		1,896
BARCT	0.11 lbs/ton coke	0.14 lbs/ton acid		0.14 lbs/ton acid
BARCT/Start EF	0.05 (=0.11/2.47)	0.04 (=0.14/3.93)		0.04 (=0.14/3.93)

TABLE 12-1 (Continue)

Equipment	Glass Plant	Cement Plant		Costs and Cost Effectiveness (including emission reductions for existing scrubber but not costs since the scrubber was installed for R1105.1)
Facility		**Kilns**	**Coal Fired Boiler**	
Control Technology /Vendor	WGS-TriMer	Limestone Absorber-BoldEco	DGS or Limestone Abs - BoldEco	
Present Worth Value ($ million)	8.8	43.7	12.6	**1,026**
Scenario 1 - most stringent	**1 ppmv**	**1 ppmv**	**5ppmv**	
Performance Level	99%	95% (1-2 ppmv)	95% (5 ppmv)	**1,026**
Emission Reductions (tpd)	0.19	0.25	0.36	**7.5**
Cost Effectiveness ($/ton)	4,988	18,893	3,818	**15,008**
BARCT	0.0058 lbs/ton glass	0.03 lbs/ton clinker	95%	
BARCT/Start EF	0.002 (=0.0058/2.51)	0.6 (=0.03/0.05)	0.05 (=1-0.95)	
Scenario 2 - consultants	**1 ppmv**	**1 ppmv**		
Performance Level	99%	95% (1-2 ppmv)	Not use in 2005	**1,007**
Emission Reductions (tpd)	0.194	0.25		**6.53**
Cost Effectiveness ($/ton)	4,988	18,893		**16,908**
BARCT	0.0058 lbs/ton glass	0.03 lbs/ton clinker		
BARCT/Start EF	0.002 (=0.0058/2.51)	0.6 (=0.03/0.05)		
Scenario 3A - staff's	**5 pppmv - 2 WGS**	**5 ppmv - 2 DGS**		**11 WGS, 2 DGS**
Performance Level	2WGS 95% (5 ppmv)	2DGS 93% (5ppmv)	Not use in 2005	**745**
Emission Reductions (tpd)	0.186	0.248		**6.20**
Cost Effectiveness ($/ton)	5,198	19,300		**13,160**
BARCT	0.03 lbs/ton glass	0.04 lbs/ton clinker		**($15,845 per ton if excluding emi reductions of existing scrubber in the cost effectiveness calculation.)**
BARCT/Start EF	0.01 (=0.03/2.51)	0.74 (=0.04/0.05)		
Scenario 3B - Alternative	**10 ppmv**	**10 ppmv**		
Performance Level	2WGS 90% (10ppmv)	2DGS 90% (10 ppmv)	Not use in 2005	**884**
Emission Reductions (tpd)	0.176	0.24		**6.10**
Cost Effectiveness ($/ton)	5,487	19,942		**15,878**
BARCT	0.05 lbs/ton glass	0.05 lbs/ton clinker		
BARCT/Start EF	0.02 (=0.05/2.51)	1 (=0.05/0.05)		

Example for Refinery #2:
Maintenance costs = (Capital costs by NEC)(0.6/100) = ($49,100,000)(0.6/100) = $294,600
Operating costs = $1,446,727 (by ETS) - 48,000 (by ETS) + $294,600 (by NEC) = $1,693,327

Table 12-3 summarizes the results for SRU/TGs.

TABLE 12-3
Cost Effectiveness of Controls for SRU/TGs using NEC's Recommendations

	Ref #2	Ref #3	Ref #6
Capital Costs ($)	49,100,000	63,416,089	58,210,000
Annual Operating Costs ($)	1,693,327	570,859	3,305,106
Present Worth Values ($)	76,151,815	73,229,787	110.463,974
Cost Effectiveness ($/ton)	49,626	55,270	41,564

Cement Kilns & Coal Fired Boilers

NEC recommended wet gas scrubber as BARCT for both cement kilns and coal fired boiler but did not provide any cost estimates for wet gas scrubbers. NEC commented that ETS's analysis did not include contingencies. With contingencies added as recommended by NEC, the capital costs were estimated as:

- $32,700,000 for cement kilns (approximately 67% higher than ETS's estimate)
- $10,300,000 for coal fired boiler (approximately 67% higher than ETS's estimate)

NEC estimated that the maintenance costs should be higher for cement kilns, increased from $312,000 as estimated by ETS to $467,000, and turnaround would occur every 2 years instead of every 5 years. Staff estimates of the cost effectiveness using NEC's input are provided the results in Table 12-4.

TABLE 12-4
Cost Effectiveness of Controls for Cement Facility using NEC's Recommendations

	Cement Kilns	Coal Fired Boiler
Capital Costs ($)	32,700,000	10,300,000
Annual Operating Costs ($)	1,633,250	$385,293
Present Worth Values ($)	62,086,085	17,498,910
Cost Effectiveness ($/ton)	26,824	5,312

Glass Furnaces

NEC recommended the use of a large bore, open throat wet gas scrubber as BARCT for glass furnaces instead of packed-bed wet gas scrubber. NEC recommended a different location than ETS which results in an increase in the costs for ducting, substation additions, knife gate valve, and indirect costs. While NEC did not propose cost estimates for a large bore, open throat WGS, NEC agreed with ETS that wet gas scrubber would be cost effective. Without any cost information from NEC, staff used ETS's data instead.

Sulfuric Acid Plants

NEC agreed that wet gas scrubber should be recommended as BARCT for sulfuric acid plants, but estimated the following capital costs:

- $18,746,000 for Plant 1 (3 times higher than ETS's estimate)
- $1,500,000 for modification of Plant 2 at a refinery (3 times higher than ETS's estimate)

NEC recommended a turnaround every 5 years for sulfuric acid plants, and an additional maintenance cost of 0.6% capital costs. Following NEC's recommendations, staff estimated the cost effectiveness shown in Table 12-5.

TABLE 12-5
Cost Effectiveness of Controls for Sulfuric Acid Plants using NEC's Recommendations

	Plant 1	Plant 2 Modification
Capital Costs ($)	18,746,000	1,500,000
Annual Operating Costs ($)	684,092	$71,610
Present Worth Values ($)	29,701,459	2,640,148
Cost Effectiveness ($/ton)	2,833	8,768

Coke Calciner

NEC recommended wet gas scrubber as BARCT for coke calciner, estimated a capital cost of $45,700,000, recommended every 2 years turnaround for the unit, and maintenance cost of 0.6% capital costs. Based on NEC's recommendations, staff estimated the cost effectiveness shown in Table 12-6:

TABLE 12-6
Cost Effectiveness of Controls for Coke Calciner Using NEC's Recommendations

Capital Costs ($)	45,700,000
Annual Operating Costs ($)	734,188
Present Worth Values ($)	58,857,089
Cost Effectiveness ($/ton)	23,036

12.3 Comparison of Costs and Cost-Effectiveness

In calculating the overall cost effectiveness using NEC's data for the project, staff 1) excluded cost-ineffective scenarios (cost effectiveness more than $50,000 per ton emission reduced), and 2) excluded the scenarios where emission targets already had been met.

Present Worth Values (million dollars) = (81.29+114.58+84.08+109.33) for FCCUs + (76.15+110.46) for SRU/TGs + 58.86 for coke calciner + (2.64+29.70) for sulfuric acid + 8.83 for glass + 62.1 for cement kilns = 389.29 + 186.62+58.86+ 32.34 + 8.83 + 62.09
= $738 million.

Emission Reductions (tons per day) = (0.58+0.28+0.20+0.94) for FCCUs + (0.17+0.29) for SRU/TGs + 0.28 for coke calciner + (0.03+1) for sulfuric acid + 0.19 for glass + 0.25 for cement = 2.01 + 0.46 + 0.28 + 1.03 + 0.19 + 0.25 = 4.22 tpd

Cost Effectiveness = 738.02 millions / (4.22 tpd x 365 days per year x 25 years) = $15,516 per ton SOx reduced = **$19 K per ton**

A comparison between the total present worth values estimated by ETS/AEC, NEXIDEA and staff's estimates based on NEC's recommendations is shown in Tables 12-7 and 12-8.

TABLE 12-7
Comparison of Costs for Scenario 3A of Staff's Proposal

		ETS/AEC and NEXIDEA		Norton Engineering (NEC)	
Equipment Category	**Proposed Standard (ppmv)**	**Emission Reductions from 2005 Baseline (tpd)**	**Present Worth Values ($ Million)**	**Emission Reductions (tpd)**	**Present Worth Values ($ Million)**
Sulfuric Acid	10	1.03	19	1.03	32.34
Glass	5	0.19	8.83	0.19	8.83 (as ETS)
Calciner	10	0.28	25.3	0.28	58.86
Cement	5	0.25	43.7	0.25	62.09
FCCU	5	2.01	359	2.01	389.28
SRU/TG	5	0.60	174	0.45	186.61
Total		**4.36***	**629.83**	**4.21**	**738.02**

*The total emission reductions from 2005 baseline are 5.36 tons per day which include the 1.00 tons per day early reductions already in place for FCCU to meet R1105.1 requirement and SRU to meet other regulatory requirement.

TABLE 12-8
Comparison of Cost Effectiveness for Scenario 3A of Staff's Proposal

Equipment Category	**Proposed Standard (ppmv)**	**Cost Effectiveness and Cost Effectiveness Range ($/ton) Based on ETS/AEC/NEXIDEA**	**Cost Effectiveness and Cost Effectiveness Range ($/ton) Based on Input from Norton Engineering**
Sulfuric Acid	10	2,016 (1,896 – 5,556)	3,431 (2,833 – 8,768)
Glass	5	5,198	5,198 (ETS's estimate)
Coke Calciner	10	9,902	23,036
Cement	5	19,300	27,402
FCCU	5	19,652 (12,849 – 42,103)	21,271 (12,782 – 45,120)
SRU/TG	5	31,455 (12,880 – 39,000)	44,514 (41,563 – 49,626)
Weighted Average		**15,845**	**19,199**

The analyses above indicated that the overall costs and cost effectiveness recalculated based on input from are within +20% of ETS/NEXIDEA's estimates. Staff concluded that ETS Inc. and NEXIDEA's estimates are valid.

12.4 Cost Effectiveness for Scenario 4 and Scenario 5

The following two scenarios are added to the analysis in Chapter 12:

Scenario 4 – In this scenario, as shown in Table 12-9, SRU/TG will not be subject to new BARCT:

Present Worth Values using ETS/AEC and NEXIDEA's costs = $455.83 million
Emission reductions = 3.76 tons per day
Cost effectiveness = $13.29 K per ton ($16 K per ton if using NEC's data)

TABLE 12- 9
Costs and Cost Effectiveness for Scenario 4

Equipment Category	Proposed Standard (ppmv)	Emission Reductions from 2005 Baseline (tpd)	Present Worth Values ($ Million)
Sulfuric Acid	10	1.03	19
Glass	5	0.19	8.83
Calciner	10	0.28	25.3
Cement	5	0.25	43.7
FCCU	5	2.01	359
SRU/TG	N/A	0.00	0.00
Total		**3.76***	**455.83**

*One ton per day reduction from 2005 baseline is already in place for an FCCU and a SRU/TG

Scenario 5 – In this scenario, as shown in Table 12-10, there will be no BARCT for SRU/TGs, FCCUs, and cement kilns. This scenario is intended to mimic the reduction estimated in the 2007 AQMP. The emission reductions of 1.5 tpd from 2005 is equivalent to approximately 3.23 tpd RTC reductions due to the unused RTCs available in the market (1.5 tpd emission reductions + 1.73 tpd unused RTCs = 3.23 tpd)~~:~~

Present Worth Values using ETS/AEC and NEXIDEA's costs = $53.13 million
Emission reductions = 1.50 tons per day
Cost effectiveness = $3.88 K per ton ($7.31 K per ton if using NEC data)

TABLE 12- 10
Costs and Cost Effectiveness for Scenario 5

Equipment Category	**Proposed Standard (ppmv)**	**Emission Reductions from 2005 Baseline (tpd)**	**Present Worth Values ($ Million)**
Sulfuric Acid	10	1.03	19
Glass	5	0.19	8.83
Calciner	N/A	0.28	25.3
Cement	N/A	0.00	0.00
FCCU	Tier 1	0.00	0.00
SRU/TG	N/A	0.00	0.00
Total		**1.50**	**53.13**

*One ton per day reduction from 2005 is already in place for an FCCU and a SRU/TG

12.5 Incremental Cost Effectiveness

To assess the incremental cost effectiveness as required under H&SC §40440.11, staff proposal is compared to the most stringent proposal proposed by the consultants. Comparing the consultants' proposal (including modifications for fuel gas treatment system) and staff's current proposal (not including modifications for fuel gas treatment system), the cost attributed to an additional ~~0.33~~1.17 tpd incremental emission reductions was $~~262~~377 million, which translated to **an incremental cost effectiveness of $~~87~~35 K per incremental ton SOx reduced**.[66] This significantly high level of incremental cost between the two options was the driving force leading staff to select the BARCT levels in Scenario 3. In staff assessment, the BARCT levels in Scenario 3 seeks to optimize the efficacy of the staff proposal - maximizing emission reductions and balancing the requirements for additional controls with economic impacts. The BARCT levels in Scenario 3 finally reflect "*... emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source."* as required by California Health and Safety (H&S) Code §40406.

12.6 Comparison of Cost Effectiveness to Other Rules Adopted by the Governing Board

The weighted average cost effectiveness of staff's proposal is approximately $~~13~~15 K - $19 K per ton of SOx reduced, or equivalent to $1K - $1.3 K per ton NOx reduced, or $~~9~~10 K – $13 K per ton PM2.5 reduced. [67]

[66] Incremental cost effectiveness = (1,007 – ~~745~~630) million dollars / ((6.53 – (6.20 - 0.85)) tpd x 365 days per year x 25 years) = $ ~~87,007~~35,312 per ton.

[67] Staff used the following equivalency factor: 1 ton of SOx reduced will have the same effect as 15 tons of NOx reduced, or 1.5 tons of PM2.5 reduced (Appendix C of CARB's 2007 SIP Submittal.)

The cost effectiveness factors should only be used as a relative measurement for comparison. Table 12-3 shows a comparison between the cost effectiveness derived for the 2009 SOx RECLAIM to the cost effectiveness of the 2005 NOx RECLAIM and other command-and-control rules.

As shown in this table, controlling SOx to the BARCT levels proposed by staff would result in cost effectiveness which mostly falls within, or lower than, the range of the rule cost effectiveness approved by the Governing Board in the past.

TABLE 12-3
Cost Effectiveness Comparison

2009 SOx RECLAIM ($/ton SOx reduced)	Command-Control SOx Rule
Sulfuric acid plant: $2K per ton SOx reduced Glass melting furnace: $5K per ton SOx reduced Coke calciner: $10K per ton SOx reduced FCCUs: $20K per ton of SOx reduced Cement kilns: $19K per ton SOx reduced SRU/TGTUs: $26K per ton of SOx reduced Project Overall: $13K per ton SOx	Flares: $5K - $9K per ton of SOx reduced (Rule 1118 amended 11/4/05)
2009 SOx RECLAIM ($/equivalent ton NOx reduced) (1)	**2005 NOx RECLAIM**
Sulfuric acid plant: $133 per ton NOx reduced Glass melting furnace: $333 per ton NOx reduced Coke calciner: $700 per ton NOx reduced FCCUs: $2K per ton NOx reduced Cement kilns: $2K per ton NOx reduced SRU/TGTUs: $3K per ton NOx reduced Project Overall: $1K per ton NOx reduced	Metal melting/heat treating and miscellaneous combustion: $4K – $11K per ton of NOx reduced Industrial boilers: $9K - $10K per ton FCCUs, refinery boilers/heaters: $11K-$17K per ton
2009 SOx RECLAIM ($/equivalent ton PM2.5 reduced) (1)	**Command-Control PM Rules**
Sulfuric acid plant: $1K per ton PM2.5 reduced Glass melting furnace: $3K per ton PM2.5 reduced Coke calciner: $6.5 K per ton PM2.5 reduced FCCUs: $13K per ton PM2.5 reduced Cement kilns: $12K per ton PM2.5 reduced SRU/TGTUs: $17K per ton PM2.5 reduced Project Overall: $9K per ton PM2.5 reduced	FCCUs: $13K-$23K per ton filterable PM, $3-$5K per ton filterable and condensable (Rule 1105.1, adopted 11/7/03) Coke/Coal/Sulfur Handling: $3-$30K per ton PM10 (Rule 1158, amended 6/11/99)

1) The comparison in this table uses the following equivalency: of 1 ton of SOx reduced has an equivalent effect to 15 tons of NOx reduced, or 1.5 tons of PM2.5 reduced provided in Appendix C to CARB's 2007 SIP Submittal.

Chapter 13 – RTC Reductions & Implementation

13.1 RTC Reductions Estimated from 1997 Baseline

Staff applied the same methodology used for NOx RECLAIM to estimate the projected year 201~~4~~9 SOx emissions for the entire SOx RECLAIM universe as follows:

Projected Emissions at New BARCT Levels = (1997 Baseline x Growth Factor$_{2019}$*) x New BARCT Adjustment Factor (or Tier 1, if no new BARCT is recommended)*

Where:

Projected Emissions at New BARCT Levels = Emissions in year 201~~4~~9 at new BARCT levels.
1997 Baseline =Actual emissions from July 1, 1997 – June 30, 1998. [68]
Growth Factor$_{2019}$ *= Growth factor from 1997 – 201~~4~~9 for each facility*
New BARCT Adjustment Factor = New BARCT Emission Factor / Starting Emission Factor (in Table 2 of Rule 2002)

Staff applied the 10% upward adjustment factor to the 201~~4~~9 projected emissions at new BARCT levels, and ~~estimated~~calculated the ~~projected~~ year 201~~4~~9 RTC reductions for each of the ~~four~~ scenarios described in Chapter ~~18~~13 as follows:

Programmatic RTC Reductions = ~~Current RTC Holdings~~11.77 - [Projected Emissions at New BARCT Levels x 10% Compliance Margin]

Where:

~~Current RTC Holding = 11.76 tons per day for year 2003 and beyond~~
Projected Emissions at New BARCT Levels = Remaining emissions of the entire SOx universe in year 201~~4~~9

The entire SOx RECLAIM universe was captured in this approach. In this approach, it was assumed that the year 1997 emission rates were similar to the starting emission factors. Staff estimated the projected remaining 201~~4~~9 emissions, the RTC reductions and the percent reductions for the ~~four~~ scenarios outlined in Chapter 12: Scenario 1 represented the impacts of the most stringent control measures, Scenario 2 represented the impacts based on the consultants' recommendations, Scenario 3A reflected staff's recommendations, Scenario 3B and Scenario 4 are ~~is an~~ alternatives to staff's proposal, and the last Scenario 5 is to get the minimum of 3 tons per day reductions. The RTC reductions for Scenario 3A, 4 and 5 ~~results~~ are summarized in Table 13-1~~ and shown in details in Table 13-2~~. Scenarios 1 and 2 will result in more than 70% RTC reduction, and Scenario 3B will result in approximately the same shave as Scenario 3A.

[68] In this analysis, staff used the actual CEMS reported emissions from July 1, 1997 – June 30, 1998. The period used in the 2003 AQMP is from July 1, 1996 – June 30, 1997. According to the RECLAIM Annual Audit Reports based on the CEMS data, the inventory for the compliance year 1996 was 6,484 lbs (17.76 tpd), and the inventory for the compliance year 1997 was 6,464 lbs (17.71 tpd). Since there is very little difference between the two inventories, staff believes that the results presented here, even for the 1997-1998 period, would reflect the 1996-1997 period as well.

~~TABLE 13-1~~

~~Projected Year 2014 RTC Reductions Estimated Based on 1997 Baseline~~

~~As shown in Table 19-1:~~

~~1)At the BARCT levels recommended by the consultants (Scenario 2), the RTC reductions would be about 8 tons per day in year 2014 (70% reductions);~~

~~2)Staff's current recommendation is Scenario 3, about 7.5 tons per day RTC reductions (64% reductions).~~

As a result of the current BARCT analyses, staff proposal is to reduce the RTC holdings by ~~7.5~~6.14 tons per day (~~64%~~55% reduction of the current 11.77~~6~~ tons per day RTC holdings) to ensure that the SOx market incentive program will *"achieve an equivalent or greater level of emission reductions at an equivalent or lower cost as would have been achieved under a command-and-control rule"* as required by California H&S Code §39616.

~~There are facilities that have no equipment subject to the proposed new BARCT. To keep these facilities in the market and allow them to operate without becoming incompliance, staff will be proposing a shave mechanism that may provide an alternative shave percentatge to these facilities, or exempt these facilities from the shave at this proposed rule amendment.~~

In addition, staff proposes a ~~six~~eight-year implementation program to get 6.1 tpd RTC reduction:

- 1.5 tons per day reductions in Compliance Year 2012
- 1.5 tons per day reductions in Compliance Year 2013
- 1.5 tons per day reductions in Compliance Year 2014
- ~~1.0~~0.32 ton per day reductions in Compliance Year 2015
- ~~1.0~~0.32 ton per day reductions in Compliance Year 2016
- ~~1.0~~0.32 ton per day reductions in Compliance Year 2017
- 0.32 ton per day reductions in Compliance Year 2018
- 0.32 ton per day reductions in Compliance Year 2019

The first 4.5 tons per day reduction will meet and then exceed the commitment under the 2007 AQMP, to help the Basin achieve the federal annual average PM2.5 standard by 2014. The remaining reductions will help the Basin to achieve the federal 24-hour average standard by 2020.

It should be noted that the difference between the RTC holdings of 11.7~~6~~7 tons per day and the actual emissions of ~~10~~9.22 tons per day in year 200~~8~~5 is about~~more than 1.75~~ 2.55 tons per day. This margin can be proven quite useful in meeting the proposed emission reductions during the initial phase of implementation. The remaining tons per day actual emission reductions in compliance year 2014 and beyond must be generated by implementing additional control measures. Assuming the rule is adopted in 2010, a 4 to 5-year window is likely needed to implement all control measures recommended by staff and the consultants. The consultants estimated about 2 - 3 years for implementation. An additional 2 years may be needed to reconcile the turn-around for some refineries in the District. To ease the implementation of this large project, especially to ease some environmental/energy impacts that may occur, staff recommends spreading the ~~remaining~~ tons per day RTC reductions into ~~6~~eight years, from 2012 to ~~2017~~2019.

TABLE 13-1 - RTC Reductions Estimated From 1997 Baseline

	AQMP Method - Projected to 2019											
Equipment Type	**Audited 97-98 Fiscal tpd**	**Growth Factor 1997-2019**	**2019 with growth**	**Scenario 3 - Staff's Proposal**			**Scenario 4 - Intermediate**			**Scenario 5 - AQMP**		
				BARCT Adj Factor	**ReM**	**ReD**	**BARCT Adj Factor**	**ReM**	**ReD**	**BARCT Adj Factor**	**ReM**	**ReD**
FCCUs	**5.68**	1.00	5.68	0.06	0.34	5.34	0.06	0.34	5.34	0.26	1.48	4.20
SRU/TG	**2.03**	1.00	2.03	0.63	1.28	0.75	1.00	2.03	0.00	1.00	2.03	0.00
Coke Calciner	**1.31**	1.00	1.31	0.05	0.07	1.25	0.05	0.07	1.25	0.05	0.07	1.25
Sulfuric Acid	**1.06**	1.30	1.37	0.04	0.05	1.31	0.04	0.05	1.31	0.04	0.05	1.31
Glass Melting Furnace	**1.71**	1.45	2.48	0.01	0.02	2.45	0.01	0.02	2.45	0.01	0.02	2.45
Cement Kilns	**0.53**	2.58	1.36	0.74	1.01	0.35	0.74	1.01	0.35	1.00	1.36	0.00
Boilers/Heaters	**6.11**	1.00	6.11	0.20	1.22	4.88	0.20	1.22	4.88	0.20	1.22	4.88
Total Major Equipment	**18.42**	1.10	20.33		3.99	16.34		4.74	15.59		6.23	14.10
Others	**1.06**	1.11	1.18		1.18			1.18			1.18	
Total Remaining In Year 2019 With Growth (Minus 0.054 tpd reductions from R431.1 & R431.2 for AQMP Method)				**5.12**			5.87			7.36		
1.1 x (Total Remaining)				**5.63**			6.45					
RTC Reduction in Yr 2019 w 1.1 Factor = 11.77 - (1.1xTotal Remaining)				**6.14**			5.32					
For alternative shave, % reduction w 1.1 = (shave/11.09)				**55%**			48%					
RTC Reduction in Year 2019 w/o 1.19 Factor = 11.77 - (1.19*Remaining)										3.00		
% Reduction Across Universe w/o 1.1 to compare w AQMP = (shave/11.78)										25%		

13.2 Alternative Shave

As a result of staff's analysis in Section 13.1, the overall proposed shave is approximately ~~64~~52% across the 32 facilities in the SOx universe. Staff received comments from the 22 facilities with no equipment subject to new BARCT indicating that the uniform shave was not equitable, and would create significant difficulties for them to stay in compliance, and indicated that they had limited ability to buy RTCs from large facilities

Because of the non-uniform characteristics (actual emissions and RTC distributions) of the SOx RECLAIM market (11 major facilities hold 87% RTCs and contribute more than 90~~4~~% of emissions, and the remaining 21 facilities hold only 6% RTCs and contribute about 7~~6~~% of emissions), uniform percent shave ~~of 64%~~ across the board ~~may not be~~is not the ultimate solution. The 21 facilities that have no equipment subject to the new BARCT cannot reduce their emissions further and cannot sustain operation and remain in compliance after the shave. To keep the 21 facilities active in the SOx market, staff is proposing to not shave the RTC holdings for these facilities if the RTC holdings are below their initial allocations provided to these facilities at the start of the RECLAIM program. However, the amount of RTC holdings above their initial allocations will be shaved at the same rate as other 11 facilities and investors. With this approach, staff estimated that instead of ~~64%~~ shaveing across the board, the 11 facilities will have a shave of ~~67.5%~~55%~~ and the 21 remaining facilities will have an equal shave of 4%. Alternatively~~, 18 of the 21 facilities ~~may be~~ will be exempt totally from the shave, and 3 of the 21 facilities that have RTC holdings above their initial allocations ~~may~~ will be shaved to the initial allocation levels. ~~Staff may refine the alternative shave approach in the future to address comments and input from the stakeholders.~~Any traded RTCs from August 29, 2009 to the date of adoption will also be shaved at the rate of the 11 facilities.

The results of this analysis are presented in Table 13-2

13.3 RTC Reductions Estimated from 2005 Baseline

One of the elements included in the Work Plan presented to our Governing Board in January 2010 is the commitment for staff to work closely with the Western States Petroleum Associations (WSPA) and its members in evaluating its alternative proposal. Staff held numerous meetings with WSPA and its members on this subject. As part of its proposal, on July 30, 2010, WSPA and the refineries proposed the 2005 baseline to be used to estimate the RTC reductions arguing that the 2005 baseline has been used to estimate cost effectiveness by the consultants and the 2005 emissions represent the most current emission profile for SOx RECLAIM. In addition, WSPA and its members proposed to exclude RTCs converted from ERCs (1.98 tons per day) from any future shave. WSPA's proposal was obscure and did not show how the RTC reductions were related to actual emission reductions estimated from the 2005 baseline. It seems that WSPA's position was to treat RTC reductions as equivalent to actual emission reductions, ignoring the surplus RTCs in the market. Before July 2010, WSPA proposed a 25% shave characterized as an emission reduction shave. On August 18, 2010, WSPA revised its proposal agreeing to 33% shave (3.9 tpd) across the board by the end of 2019. On September 16, 2010, WSPA again revised its proposal agreeing to 40% shave (4.7 tpd) across the board by the end of 2019.[69] In order to fully understand WSPA's proposal and provide meaningful comments to WSPA, staff contacted WSPA several times since July 30 to ask for an explanation on its methodology, specifically how to calculate the percent shave and RTC reductions from actual emission reductions. Unfortunately, WSPA offered very limited explanation to staff. To keep the project moving in a positive direction, staff provides the following initial comments on WSPA's proposal.

SOx RECLAIM started in 1993 and the initial allocations (or RTCs) provided to the RECLAIM facilities were ample, generally more than the amount that they emitted. The surplus of RTCs in 2005 is about 1.73 tons per day and the surplus of RTCs in 2008 is about 2.55 tons per day. The amount RTCs converted from ERCs contributed to the size of the surplus. For the RECLAIM facilities to actually install BARCT and reduce "real" emissions, the surplus RTCs must be removed. RTCs reflect the "Potential to Emit" and thus even though RTCs carry the same unit (i.e. in lbs SOx) as actual emissions, they represent different "currencies" than actual emissions. To fully demonstrate command-and-control equivalency due to the implementation of BARCT, due to the surplus, the amount of RTC reductions should be more than the amount of actual emission reductions and the percent reduction estimated using RTCs should be higher than the percent reduction estimated using actual emission reductions.

It seems that the proposal by WSPA and its members calls for the calculation of the percent shave by taking the ratio of the actual emission reductions estimated off the 2005 baseline emissions over the RTCs held in the market excluding any RTC converted from ERCs (1.98 tpd) at the inception of the RECLAIM program for which WSPA argued that should be excluded from any future shave. Staff acknowledges that the 2005 year emissions were used as a baseline by the consultants to formulate their recommendation on feasibility and cost of controls because they reflected the most recent year emission profile available at the time. However, dividing the "emission reductions" estimated off the 2005 baseline by the RTCs to derive the percent reduction amounts to using two different "currencies" to compute a percent figure. This approach will not yield a result that can be used to demonstrate equivalency to command-and-control. Staff uses the "remaining emissions", a constant currency, to calculate the amount of shave and to compare with a command-and-control program.

Furthermore, WSPA and the refineries proposed to exclude RTCs converted from ERCs (1.98 tons per day) from any future shave which is inconsistent with the RECLAIM program. As explained above, the RTCs converted from ERCs (1.98 tons per day) is a layer of cushion added to the surplus. Integrating the shave through this layer of surplus is one of the RECLAIM approach since the start of the program in 1993. The RTCs converted from ERCs were shaved approximately 35% from Tier 1 to Tier 2 to match AQMP emission budgets for the RECLAIM program. It was clearly the Board's policy to achieve programmatic equivalency with command & control without providing a special status to ERC converted to RTCs. When NOx program was shaved in 2005, ERCs converted to RTCs were treated the same as regular RTCs. Future economic growth was included in the emission projection. The RTCs converted to ERCs have also been used by many of the RECLAIM facilities in lieu of their emission reductions requirements under Tier 1 BARCT, which is not allowed for non-RECLAIM facilities.

[69] WSPA's presentation to staff on July 30, 2010 and August 18, 2010; WSPA's proposal to Barry Wallerstein on September 16, 2010; and WSPA's presentation at the Refinery Committee Meeting on September 22, 2010.

Therefore, it would be appropriate to include these RTCs in the future shave, retain equivalency with command and control, and attain the air quality objectives of the region. In addition, for non-RECLAIM facilities, the emissions from shutdown equipment are required to be discounted to BACT level, before ERCs can be issued. Furthermore, new or modifying non-RECLAIM facilities undergoing New Source Review (NSR) are required to offset any emission increase for SOx and NOx by a 1.2 to 1.0 ratio. On the other hand, RECLAIM facilities undergoing NSR are not subject to the 1.2 to 1.0 offset ratio that non-RECLAIM facilities are. The following table summarizes the comparison between ERC generation and use between RECLAIM and non-RECLAIM program. Considering all of the above facts plus the benefits incurred by the RECLAIM facilities utilizing such RTCs during the 17-year life of the program since 1993, staff believes that the 1.98 tons per day RTCs converted from ERCs do not deserve a special status, and thus the 1.98 tons per day RTCs converted from ERCs, which add to the RTC surplus, should be subject to the future RTC shave of 55%. In summary:

	Non-RECLAIM	RECLAIM
Usable in lieu of BARCT	Yes	No
BACT Discount	No	Yes
Offset Ratio 1.2 to 1.0	Yes	No

TABLE 13-2 – ~~Alternative~~ Shave Adjustment Factors for Staff's Proposal – 55% Shave in 2019

Year 2012 RTC Inventory as of August 29, 2009

11 major	21 others	investors	total
10.21	**0.73**	**0.83**	**11.77**

Three of 21 facilities have RTC holdings larger than initial allocations by a total of 0.05 tpd

Therefore, non-shaved portion for 22 facilities - 0.73 - 0.05 = 0.68 tpd

Estimation of Adjustment Factors for Rule 2002

	RTC subject to shave for 11 major facilities, 3 of the remaining 21 facilities, and investors	RTC Non-Shaved Portion	RTC Reduction for the following year	RTC for Shave	Adjustment Factor for next year	TOTAL (total for shave + non-shaved)
Start Year 2011	11.09	0.68		11.09		11.09+0.68=11.77
End Year 2011			1.5	11.09-1.5=9.59	9.59/11.09=0.865	
Start Year 2012	11.09x0.865=9.590	0.68		9.59		10.27
End Year2012			1.5	9.59-1.5=8.09	8.09/11.09=0.729	
Start Year 2013	11.09x0.729=8.090	0.68		8.09		8.77
End Year 2013			1.5	8.09-1.5=6.59	6.59/11.09=0.594	
Start Year 2014	11.09x0.594=6.590	0.68		6.590		7.27
End Year 2014			0.32	6.59-0.32=6.27	6.27/11.09=0.565	
Start Year 2015	11.09x0.565=6.27	0.68		6.270		6.95
End Year 2015			0.32	6.27-0.32=5.95	5.95/11.09=0.5365	
Start Year 2016	11.09x0.537=5.96	0.68		5.960		6.63
End Year 2016			0.32	5.96-0.32=5.635	5.635/11.09=0.508	
Start Year 2017	11.09x0.508=5.635	0.68		5.635		6.31
End Year 2017			0.32	5.635-0.32=5.315	5.315/11.09=0.479	
Start Year 2018	11.09x0.479=5.315	0.68		5.315		5.99
End Year 2018			0.32	5.315-0.32=4.995	4.995/11.09=0.45	
Start Year 2019	11.09x0.45=4.99	0.68		**4.99**		**5.67**
End Year 2019			0			
	Total reduction in 8 years (2012-2019)		**6.100**			

Summary

RTC HOLDINGS	RTC subject to shave	Non-shaved	Total
Starting	11.09	0.68	**11.77**
Ending (Remaining)	4.99	0.68	**5.67**
Reduction	6.10	0.00	**6.10**
% reduction	**55.0%**	**0%**	

This table includes the following RTC Holdings: 10.21 tpd from 11 major facilities, 0.05 tpd from 3 of the remaining 21 facilities, and 0.83 tpd from investors

Chapter 14 – Comments & Responses

WSPA's Comments Received from March-August 2010

Stranded Investments of Rule 1105.1

Comment #1

Actual cost information from refineries has been submitted to the District. We understand that Staff has initially reviewed the information and still feel that the documented costs seem "high" compared to District expectations.

The District Staff's position is a concern to WSPA and our members, because the affected refineries documented actual costs incurred to comply with previous SCAQMD rules. WSPA members have been open and factual in providing this documentation.

The result is entirely consistent with WSPA's previous Rule 1105.1 cost-survey that showed implementation costs were 3-5 times (or more) greater than the preliminary cost estimates made by District Staff and District consultants. We believe the documented actual installation costs are superior to any pre-rule cost estimates.

The District should accept the cost data provided by the refineries and acknowledge the fact that the actual costs are higher than the District's pre-implementation estimates. As we move forward, the District should consider these actual costs in establishing future cost estimates for control technology.

Response #1

The cost information submitted by the refineries to comply with Rule 1105.1 has varied considerably in content and level of detail. On this basis, it has been very difficult for staff to ascertain costs that were directly attributable to the Rule 1105.1 and the costs that were the result of corporate decisions or those that extend to other facility operations (e.g., augmentation of substations).

However, there was a reasonable agreement relative to the equipment cost estimates and actual equipment cost incurred but large divergence relative to the actual installation costs asserted by the refinery and original estimates by the AQMD consultant and even WSPA's consultant. The industry's delay in implementation (due to the litigation initiated by WSPA) had a direct impact on the increased costs on construction materials and labor. As reported by the refineries, all refineries selected to use the same ESP's manufacturer (Hamon Research Cottrell) and same contractors (Jacobs Engineering/ Hamon Research Cottrell) during a short construction/installation period from the mid of 2007 – mid of 2008. This compressed construction schedule had a strong negative impact on the union labor costs and the management costs, and thus inflated the implementation costs of the projects. In addition, all refineries selected to build extra redundancy to their ESPs, and upgrade other systems (e.g. substation, NOx and SOx monitoring) that may not be directly related to the FCCUs. Furthermore, the market experienced a surge in steel prices in 2008. These facts together explain the differences in the costs estimated pre- and post- rule development by staff and AQMD consultants as well as those that were provided by industry. Please also note that all of the cost figures submitted significantly varies with the costs incurred by Chevron for their ESP installation in the early nineties, even when adjusted to current dollars. Detailed analysis is shown in Appendix E.

It is very important to note that in several meetings with the District, WSPA members indicated that if they installed wet gas scrubbers, they need to remove the ESPs and thus the installation costs for the ESPs would be stranded. None of the consultants supported the perspective that there is a stranded investment issue. In other words, based on the feedback received, the installation of the SOx control technology under consideration to meet the proposed BARCT levels will not necessitate removal of previously installed equipment to control PM. It is understandable that there would be certain costs associated with such equipment alterations as augmenting the exhaust flow to overcome increased pressure differentials. However, the potential problem of a stranded investment, according to the consultants, does not exist.

Legal Mandates and SOx Shave Methodology

Comment #2

In a meeting with the District on March 5, 2010, one WSPA's member cited H&S Code 39616(b)(2) – "A market-based incentive program ..... may substitute for current command and control regulations and future air quality measures that would otherwise have been adopted as part of the district's plan for attainment, and may be implemented in lieu of some or all of the control measures adopted by the district pursuant to Chapter 10 (commencing with section 40910) of Part 3." This person asked whether the District has legal authority to make BARCT more stringent for SOx, a primary pollutant that is already in attainment, solely because SOx is a precursor of PM2.5 and the Basin is not in attainment of PM2.5/PM10.

Response #2

The cited provision does not limit the market incentive program to pollutants listed under Chapter 10. Indeed, Section 39616(b)(1) provides that the District Board may adopt a market incentive program as an element of the district's plan for attainment of the state or federal ambient air quality standards. Thus, the District has legal authority that goes beyond controlling primary pollutants stated in Chapter 10. Chapter 10 covers pollutants such as NOx, SOx, and CO. In this case, the District is in non-attainment for PM2.5 and PM2.5 is a pollutant that is not covered under Chapter 10. One of the reason staff is amending Regulation XX is to reduce SOx in order to help the Basin attain the PM2.5 standards in 2015 and 2020.

It should be noted that SOx is a significant building block of PM2.5. Chemical speciation of PM2.5 samples indicated that in the South Coast Air Basin 25% of the ambient PM2.5 is attributed to contribution from sulfates. Furthermore, SOx reductions are highly effective in reducing ambient PM2.5 levels as compared to other primary and secondary contributors to PM2.5 formation (1 ton SOx = 1.5 tons PM2.5 = 15 tons NOx). Therefore, considering the level of NOx reduction needed to meet future ambient standards of PM2.5 and ozone and the fact that much of the needed NOx reductions are in the "black box", the reductions of SOx are essential for the basin to meet the federal annual standard of PM2.5 by 2015 and the federal 24-hour average standard of PM2.5 by 2020.

As indicated in the 2007 AQMP, the control strategies included in the Plan to meet the annual PM2.5 standard when fully implemented will fall short meeting the 24-hour standard by approximately 30%. Therefore, additional reductions above and beyond the control strategies committed in the 2007 AQMP for meeting the 2015 annual PM2.5 standard are necessary to meet the 24-hour PM2.5 standard in 2020. For further information, please refer to Chapter 5 of the 2007 AQMP. It should be noted that EPA is in the process of revising the PM2.5 standard.

Comment #3

In a meeting with the District on March 5, 2010, one WSPA's member cited H&S Code 39616(c)(1) "The program will result in an equivalent or greater reduction in emissions at equivalent or less cost compared with current command and control regulations and future air quality measures that would otherwise have been adopted as part of the district's plan for attainment". This person indicated that RECLAIM universe changed substantially from 1993 from 42 facilities to 32 facilities today with a very different emission profile. Why can't the district use the most current emissions distribution (e.g. 2005-2009) to estimate future RTC reductions and demonstrate attainment (or equivalency)? Why is there a need to base the estimation of RTC reductions on 94 or 97 baseline and emission profile? Does the H&S Code (or Regulation XX) restrict the district to use current emission profile?

Response #3

For a market based incentive program, staff is required by the H&S codes to conduct periodic BARCT reassessment and demonstrate equivalency with command-and-control rules which would otherwise be developed as a result of BARCT reassessment:

> *"…achieve an equivalent or greater level of emission reductions at an equivalent or lower cost as would have been achieved under a command-and-control rule"*

The H&S codes do not restrict staff in using the current emission profile in 2005 to estimate RTC shave. The H&S code requires staff to apply BARCT when it is available and cost-effective, and demonstrate equivalency with command-and-control rules. Staff selected to use the 1997 baseline to be consistent with the NOx RECLAIM approach which was also recommended by WSPA's members in 2008-2009. The 1997 baseline reflects the emission profile at the time frame where no significant SOx control effort were undertaken by the RECLAIM facilities and therefore reflects equitable capture for future control efforts than the 2005 baseline. Please refer to Section 13.3.

Comment #4

District Staff has proposed a SOx RECLAIM shave methodology that was designed to be consistent with the method used for the NOx RECLAIM shave. WSPA feels, however, that the District's proposed methodology inappropriately overstates the required reduction (i.e., % shave) in the RTC allocations, thereby making the shave extremely cost-ineffective. This holds true for both the BARCT adjustment as well as the market-adjustment that was recently proposed.

WSPA only recently (June 18) received the RTC allocation data that we requested at our meetings with Staff on March 5 and again on April 7. While the allocation data report forwarded to us by District Staff does not provide the level of detail we requested, we have begun a detailed review of the information. Having this information is a key to understanding how a reduction in RTC allocations can affect compliance costs and, indeed, the RTC market.

Response #4

WSPA is correct that the SOx shave methodology proposed by staff is consistent with the methodology used for the NOx RECLAIM shave. The idea of keeping the shave methodologies consistent was a theme that was repeatedly requested by WSPA and its members during our extensive dialogue over the last several months as well as through several comment letters. Staff believes that the proposed methodology for SOx RECLAIM, as in the case of NOx RECLAIM, reduced RTC allocations fairly and equitably, remaining true to the design principles of RECLAIM.

As mutually agreed upon in the Work Plan, staff was open to alternative proposals, and as such, when asked by WSPA, staff provided WSPA with initial allocation data that was highly resource intensive to produce. At the March 5, 2010 meeting WSPA and its members did not request the RTC allocations. At the April 7, 2010 meeting such a request was made with very little input on the level of detail. In response, staff explained that the information requested would be a very resource intensive undertaking and would take several weeks to assemble. To that end staff spent a considerable amount of time assembling the allocation tables and meeting with each of the refineries, explaining their particular allocation profile line-by-line or equipment-by-equipment specification. The level of detail and the form of the information presented was, in part, staff's effort to be sensitive to WSPA's concerns regarding confidentiality and anti-trust issues.

Comment #5

WSPA proposed methodology (WSPA's presentation in the Refinery Committee Meeting on August 18, 2010) is summarized as follows: 1) use the 2005 actual emissions as baseline, 2) no new BARCT for boilers/heaters, SRU/TGs and cement kilns, 3) no shave for 1.98 tons per day unused RTCs converted from ERCs and Clean Fuel adjustments, 4) consider 10% - 20% compliance margin consistent with the operating requirements at some facilities and past practice. WSPA's proposal results in 3.86 tpd shave. WSPA proposes 3 tpd shave by December 2014 and the remaining no sooner than December 2019. WSPA also proposes across-the-board shave.

Response #5

Please see Responses to Comment #3 and #4. Using the 2005 baseline will result in 59% shave, not 55% shave as using 1997 baseline. BARCT for heaters/boilers will remain as Tier 1, and staff did not claim any reductions from 2005 from boilers/heaters category. Staff believes that a new BARCT can be set for SRU/TGs and cement kilns at 5 ppmv because retrofit control technologies are available. A 10% compliance margin is used to be consistent with NOx RECLAIM. The 1.98 tons per day RTCs converted from ERCs should be shaved in a similar fashion than other RTCs. Currently, in RECLAIM program, the 1.98 tons per day was shaved at a rate of 35% from Tier 1 to Tier 2. In comparison, ERCs of non-RECLAIM facilities do not inherently hold their values to eternity, non-RECLAIM ERCs are often recalled and reduced per Regulation XIII. It should be noted that unused RTCs are abundant in the market (in 2005, the unused RTCs were 11.77 – 10.04 = 1.73 tpd, and in 2008, the unused RTCs were 11.77 – 9.22 = 2.55 tpd.) As such, WSPA's proposal of 3.86 tpd for future RTC shave comes short, will not result in the necessary actual emission reductions in order to provide protection to the 17 million people in the Basin against the harmful effects of PM2.5.

BARCT Determination

Comment #6

The Norton Engineering Report (released by the District on June 17 2010) has called into question the cost analyses previously performed by the District and its consultants. It appears that the ultimate conclusion of Norton Engineering is that the District's RECLAIM cost-effectiveness analysis should be revised.

Response #6

It is true that the Norton Engineering Report identified some areas of disagreement related to the cost estimates and recommendations provided by the previous consultants. However, these were limited in scope, primarily reflecting the differential cost of reassessing control equipment and their placement on the refinery property. Staff provides a thorough comparison of the approaches by the two sets of consultants in this revised draft staff report.

Comment #7

While NEC only relied upon the analysis and data provided by the initial consultants, NEC found numerous instances where the District's initial consultants erred by identifying unproven or untested technology and underestimating construction, labor or materials costs.

Response #7

We need to be clear on the term "unproven or untested" technology. In some instances, NEC indicated that the control technologies have not yet been proven or tested in the petroleum refinery and cement industry areas. However, these are not "unproven or untested" in the sense of not being commercially available or in use in other applications. These types of controls would be better characterized as transferrable technologies. NEC incorporated increased costs in order to compensate for uncertainty relative to technology transfers.

Staff did not agree with WSPA that NEC found the initial consultants severely underestimated construction, labor and materials costs. NEC has used a different approach than the initial consultants to estimate the project costs. For example, for FCCU's wet gas scrubbers, NEC indicated that: "*The NEC workup for the TIC*[70] *for four of the five plants agreed reasonably well with that of the original estimates, being within +8%/ -3%. The NEC estimate for Refinery #3 was 25% higher due to the necessity to design for particulate collection…..*" Staff has estimated the project costs based on NEC's input as shown in Chapter 12. The project costs based on the

[70] TIC = Total Installed Costs

initial consultants' input are $630 millions, and the project costs based on NEC's input are $738 millions, within 20% of the initial consultants' estimates.

Comment #8

Norton Engineering Report cites examples that would raise compliance costs in all source categories, which in turn would raise the District Staff's cost estimate for the District's proposed shave significantly above the current level of $745 million.

Response #8

When one considers the capital investment to comply with staff's proposal there is about a 21 percent cost differential between Norton Engineering and the previous consultants. Such differential are within the margin of error for the analysis conducted and cannot be viewed as significant and in fact reflect different approaches along with newly acquired data. In contrast, staff has difficulties in justifying the cost figures from WSPA which are 200 to 300 percent higher than the estimates presented by the consultants.

Comment #9

The Norton Engineering Report sheds new light on the issue of what technology is technically feasible, achieved in practice and cost-effective; therefore, it directly affects BARCT determination and should cause the District to rethink its proposed reductions in the RTC market.

Response #9

As mentioned above, the cost differential between the two sets of consultants is within the margin of error of the analysis conducted and in staff's view does not materially affect staff's earlier BARCT determination. Please also see response #7.

Comment #10

As a follow-up to the release of the Norton Engineering Report, we request that the District make the Norton Engineering staff available to meet with WSPA members individually so they can understand the details associated with the Norton Engineering Report.

Response #10

In the spirit of being sensitive to WSPA's confidentiality and anti-trust concerns, facilities and vendors in the final report by Norton Engineering are de-identified. Staff would be happy to meet with each of your members to let them know about their facility-specific information meeting with representatives of Norton Engineering may not be necessary after all.

Comment #11

WSPA requests the District to re-estimate the cost effectiveness based on Norton Engineering's estimates and make the report available to WSPA's members for comments. WSPA estimated the total costs to comply are about $2.7 billion as shown in WSPA's presentation at the Refinery Committee Meeting on August 18, 2010. On April 7, 2010, WSPA also provides staff cost estimates based on ENVIRON's report (WSPA hired ENVIRON to collect data and perform analysis with the results aggregated and de-identified). The aggregated cost estimates provided by WSPA on April 7, 2010 include: 1) Total compliance costs are about $2.85 billion for a 60%

shave, and $550 million for 25% shave; 2) Distribution of the total costs for 60% shave: $1.45 billion for FCCUs' controls, $436 million for SRU/TGs' controls, and $960 million for other improvements; and 3) Distribution of the total costs for 25% shave: $84 million for FCCUs' controls, $342 million for SRU/TGs' controls, and $127 million for other improvements. WSPA estimates $60,811.68 per ton for 60% shave scenario and $28,165 per ton for 25% shave scenario for refineries as of April 7, 2010.

Response #11

Staff is very sensitive about the costs estimated by WSPA, and plan to work in concert with WSPA to understand WSPA's estimate of almost 3 billion dollars for the proposed project. It seems that WSPA may include other costs above and beyond the scope of SOx RECLAIM. While the refineries can modernize and upgrade their facilities to respond to market demand and other regulatory requirements, it is not justifiable to attribute all of these project costs to SOx RECLAIM project.

Market Viability

Comment #12

District staff has committed to considering the use of compliance margin and non-tradable RTC accounts as tools to alleviate shortage of tradable RTC and ultimate failure of the SOx RTC market. WSPA is not aware of any progress to date.

Response #12

Staff has used 10% compliance margin in the Draft Staff Report released on January 8, 2009. Staff is proposing additional safety valves to retain market viability, for example the proposed rule language for Rule 2002 (PAR 2002(f)(1)(O)) establishes non-tradable RTC accounts starting in 2015 to be made available in the event the market price of "discrete" RTCs is higher than $50 K per ton. More specifically, in the event that the SOx RTC prices for "discrete" RTCs exceed $50,000 per ton based on the 12-month rolling average, staff will report to the Governing Board at a public hearing to be held no more than 60 days from staff's determination, which will be posted on District's web site. At the public hearing, the Governing Board will decide whether or not to convert any portion of the non-tradable/non-usable RTCs to tradable/usable RTCs. The portion of non-tradable/non-usable RTCs available for conversion will not include any portion of non-tradable/non-usable RTCs that are designated for previous compliance years and has not already been converted by the Governing Board, or any portion that has been included in the State Implementation Plan.

Water Demand & Wastewater Discharge

Comment #13

District Staff indicated they will invite representatives from water regulatory agencies, purveyors and wastewater treatment facilities "to the next Refinery Committee meeting." These representatives will be given the opportunity to provide their insights on the impact the Staff proposal will have on water supply and wastewater treatment. District Staff will also explore the extent to which the water demand can be offset by groundwater from wells owned and *operated by refineries, by recycled water, or by other means. Associated costs will also be examined.*

Response #13

Representatives from water regulatory agencies, purveyors and wastewater treatment facilities were invited and attended the Refinery Committee Meeting on August 18, 2010. Representatives of the water purveyors attended the meeting confirmed that recycled water would be made available for the refineries in a near future. In addition, CEQA staff has sent the Draft Program CEQA document to the representatives of state water regulatory agencies, purveyors and wastewater treatment facilities for their comments on this issue. District Staff believes that the water demand can be offset by groundwater from wells owned and operated by refineries, by recycled water, or by other means. Furthermore, the consultants did include the associated costs of water (e.g. they used the costs provided to them by the refineries, $900 per acre-foot recycled water) in their cost effectiveness analysis.

CEQA Implications and Permitting

Comment #14

Specifically with respect to permitting and CEQA compliance, WSPA members have not yet been contacted by District Staff for information related to construction, project emissions or any other environmental impacts. We encourage the District to address the program's effects as specifically and comprehensively as possible, so that subsequent activities at RECLAIM facilities are addressed within the scope of the EIR.

Response #14

Staff has been in direct contact with WSPA members over the last several months for information related to construction, project emissions or any other environmental impacts. Based on this information, as well as information from other sources, staff did and will continue to do their best to address the program's effects as specifically and comprehensively as possible, so that subsequent activities at RECLAIM facilities are addressed within the scope of the EIR.

Comment #15

WSPA appreciates the District's willingness to prepare a comprehensive CEQA programmatic DEIR document to help streamline the permitting process for individual projects carried out in response to the requirements of PAR XX. However, WSPA feels that several projects to reduce SOx emissions will require modification to existing Title V/RECLAIM permitted equipment, may involve changing the existing process units by adding process vessels, enlarging existing process vessels and replacing one type of chemical solution with another type. These activities will be subject to various District regulations, particularly Regulation XIII – New Source Review, Rule 1401 – New Source Review of Toxic Air Contaminants, and PSD for criteria pollutants and perhaps green house gas (GHG) emissions, as well as public review. Other projects may need offset exemption and in the absence of a SIP-approved Rule 1315, we suggest that the SCAQMD begin implementation of this element of the Work Plan as soon as possible. The first tasks would be to review issues such as the availability of offset credits, qualification for Rule 1304 offset exemption, new or larger releases to the flares, NSR and Subpart Ja applicability to flare *modifications, Best Available Control Technology (BACT), Toxics – BACT, and analysis of potential risk increase under Rule 1401.*

Response #15

Staff acknowledges WSPA's comments and will plan to work with Engineering & Compliance to address these elements related to permitting as soon as possible.

Comment #16

WSPA met with staff on April 7 and 15, 2010. WSPA hired Environ to collect data from the refineries and perform analysis with the results aggregated and de-identified. The total costs and cost effectiveness provided by WSPA for 25% shave and 60% shave scenarios are summarized below.

Total Costs ($Million) for
SOx RECLAIM Project Summarized by WSPA/ENVIRON

	For 25% Shave	*For 60% Shave*
FCCUs Contribution	*83.57 million*	*1,454.51 million*
SRUs Contribution	*341.79 million*	*436.10 million*
Others	*127.11 million*	*960.20 million*
Total Costs	*550.00 million*	*2,850.00 (2.85 billion)*
Cost Effectiveness	*$28, 165 per ton*	*$60,812 per ton*

Response #16

WSPA did not provide specific information that could be used for meaningful analysis. In addition,WSPA's cost estimates were very different than the costs that staff received from the refineries directly. Furthermore, WSPA's estimates did not reflect the 55% shave scenario that staff currently proposed. Staff identified three scenarios in WSPA's estimates that were substantially different from the consultants' estimates. Staff believes that these three estimates were exaggerated. The table below shows how staff could explain the gap between WSPA's estimates and the cost estimates based on NEC/ETS/AEC and NEXIDEA's recommendations.

Estimates	Explanation
$2,850 million	WSPA's estimate for 60% shave
-$700 million	Remove costs for boilers/heaters control options
-$101 million	Remove costs for early controls already in place
-$467 million	Remove costs for cost-ineffective units
$1,562	
-$700 million	Remove overestimated costs for FCCU's WGSs (2 outliers)
+$196 million	Add consultants' estimated for FCCU's WGSs
-$459 million	Remove overestimated costs for SRU/TG's WGS (1 outlier)
+$73 million	Add consultants' estimated for SRU/TG's WGS
Total $672 million	This compares reasonably well with the consultants' estimates of $630 - $750 million for the SOx RECLAIM project

Responses to WSPA's Comments Received on July 14, 2009

- **BARCT, Cost Effectiveness Analysis, and RTC Reduction Estimates**

Comment #1
A methodology for making the BARCT determination and calculation of the SOx reduction should be developed by the District, and understood by the stakeholders, prior to conducting any analysis or any study. Staff must stay consistent with the 2005 NOx shave methodology. The identification of baseline year, starting emission factors, control factors, etc. has been lacking.

Response #1
The methodology for BARCT determination and RTC reduction estimates is transparent, has been provided to the stakeholders as early as in April 2008, and has been discussed at the June 2009 Public Workshop, and many Working Group meetings since then.

BARCT Determination
SOx RECLAIM program is required by H&S Code 39616 code to:

> "…achieve an equivalent or greater level of emission reductions at an equivalent or lower cost as would have been achieved under a command-and-control rule"

To fulfill this requirement, staff has followed a traditional, transparent, BARCT determination methodology that is similar to the methodology used in any command-and-control rule development. The step-by-step BARCT determination process was summarized in the Draft Staff Report, Part III, released in June 2009.

It should be noted that staff is not required to focus only on achieved-in-practice and fully commercialized available control technology (i.e. technology that either is being offered commercially by vendors, or is in commercial demonstration or licensing). Staff is obligated to find technology that can potentially reduce maximum amount of pollution and meet the requirement sated in H&S Code §40406:

> "… an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, & economic impacts by each class or category of source."

~~In other words, the~~Thus technology that is both ~~must be~~ feasible and cost effective must~~to~~ be considered ~~as~~ BARCT even~~if~~ they are not yet proven achieved-in-practice. A feasible technology is a technology that has been previously installed and operated successfully at a similar type of source, or has practical potential for application to the source, i.e. has been successfully applied to similar sources with similar gas stream characteristics.

The potentially proposed BARCT levels for 7 categories of sources were first introduced to the public and the stakeholders in early April 2008, and have become the source of discussion in many Working Group meetings since then. Please refer to the Preliminary Draft Staff Report dated April 3, 2008 and subsequent Working Group meetings on April 3 and April 30, 2008 as well as in many separate task force meetings with WSPA and WSPA's members since then.

In late September 2008 to April 2009, the consultants carefully conducted another independent feasibility analyses for all of the potential BARCT identified by staff. They estimated the cost effectiveness factors for these technologies on a facility-by-facility basis. In their final reports, the consultants concluded that the proposed BARCT levels were feasible, available, and cost effective.

Subsequent to the release of the consultant studies, their recommendations were carefully evaluated by staff and subject to another step of refinement. The objective of this refinement was to optimize the effectiveness of the subsequent staff proposal by removing certain control technology recommendation with the lowest favorable cost effectiveness that allowed optimizing the emission reductions to be obtained relative to the capital investment to be incurred.

RTC Reductions Estimates & Shave Methodology

Staff followed the commenter's recommendation to stay consistent with the NOx shave methodology that was developed by the District's staff and agreed upon by WSPA and WSPA's members in 2005. Even though staff was in agreement in principal with the desire to stay consistent with the 2005 NOx shave methodology, designing a shave methodology that is workable for the SOx RECLAIM program, but remains fair and equitable is not a trivial and simple task.

To use the 2005 NOx shave methodology, staff invested tremendous amount of time and efforts to recover the 1997-1998 emissions baseline and the starting emission factors in 1993. Using the 1997-1998 emissions baseline and the 1993 starting emission factors, staff estimated the control factors and RTC reductions as shown in Part III of the Draft Staff Report presented in the June 9, 2009 Public Workshop. The RTC reductions shown in the June 2009 Staff Report (i.e. 7.09 tpd – 7.68 tpd) were very similar to the emission reductions estimated by staff in April 2008 (i.e. 6.73 tpd – 6.77 tpd.)

Comment #2
Part I of the Staff report contains premature technology recommendations by the District. The attempt to identify these candidate technologies in advance was in conflict with the concept of utilizing third party consultants to conduct a study to determine potential technology recommendations. Any proposed BARCT should be eliminated from Part I and reserved for discussion in Part III.

Response #2
Staff disagrees with the commenter's recommendation. Utilizing the third party consultants to conduct additional independent studies on BARCT from September 2008 – April 2009 should not be viewed as relinquishing the authority or obligation by staff from conducting their own independent research on BARCT and release any relevant information to the stakeholders. Part I, II and III of the Staff Report reflect the progression in the thought and evaluation process

leading to the most recent staff proposal during this rule making process. Specifically, Part III of the Staff Report has utilized the information presented in Part I of the Staff Report (i.e. feasible control technologies) and Part II (i.e. cost information) in conjunction with other information (e.g. starting emission factors, 1997-1998 emissions baseline, growth factor) to estimate the RTC reductions. This approach is consistent with the requirements in H&S Code §40406 and §39616. Staff is now retaining all the information in Part I, and combining Part III and Part IV into Part I as a complete report. Part II is reserved to serve as a summary of the consultants' analyses.

Comment #3
In the 2005 NOx Shave, District staff established the following specific criteria used to evaluate BARCT. Staff should use these criteria in evaluating measures for this SOx shave rule:

- *Does another air pollution control district or agency have BARCT that we have not identified, or have a more stringent BARCT level than the SCAQMD? WSPA's opinion: No*
- *Is the proposed BARCT level achieved in practice as retrofits? WSPA's opinion: No*
- *Is technology available and feasible for retrofits? WSPA's opinion: Feasibility must take into account environmental, economic and energy impacts, based on this NO*
- *Do manufacturers offer guarantees for achieving proposed emission levels? WSPA's opinion: Guarantee letters were all prospective - contractor has not issued, or presented evidence of, guarantees at the recommended levels and corresponding demonstrated equipment operation functioning under those guaranteed letters.*
- *Is retrofit technology cost-effective? WSPA's opinion: No*
- *Based on the above criteria, could a command and control BARCT rule have been proposed in the absence of the RECLAIM program? WSPA's opinion: No*

Response #3
Staff has examined the criteria listed above; however, staff disagrees with most of the commenter's responses to these criteria. Staff's responses are as follows:

- Does another air pollution control district or agency have BARCT that we have not identified, or have a more stringent BARCT level than the SCAQMD? Staff's response: No. Because of the severity of air pollution its seventeen (17) million residents have to endure, SCAQMD usually sets the most stringent BARCT emission standards in the nation. The more stringent BARCT standards are needed for the Basin to achieve the annual average and 24-hour PM2.5 and ozone federal and state air quality standards in 2015, and 2020, and post 2020, respectively.

- Is the proposed BARCT level achieved in practice as retrofits? Staff's response: Yes. The proposed 5 ppmv BARCT limits are achieved-in-practice for FCCUs (Valero Delaware Refinery, ConocoPhillips Refinery) and SRU/TGTUs (Sinclair Refinery, Casper Refinery.) The proposed technologies (e.g. wet/dry gas scrubbers) are commercially available, feasible to achieve 5 ppmv in all 7 equipment applications identified by staff, and they are cost effective to implement.

- Is technology available and feasible for retrofits? Staff's response: Yes. Wet/dry gas scrubbers are commercially available, feasible and cost effective for retrofits. Emerachem oxidation and absorption catalyst technology is commercially available, has been used in power plant application, but has not been used in a refinery application and the consultants' conclusion is that the technology is transferable to refinery application.

- Do manufacturers offer guarantees for achieving proposed emission levels? Staff's response: Manufacturers have provided guarantee letters to the consultants and these letters were distributed directly to the refineries, as well as the Governing Board members and the public in the Stationary Source Committee meeting June 2009.

- Is retrofit technology cost-effective? Staff's response: Yes. Please refer to the consultants' analyses.

- Based on the above criteria, could a command and control BARCT rule have been proposed in the absence of the RECLAIM program? Staff's response: Yes. It should be noted that if a command and control BARCT rule would be proposed, they individually could have more stringent reduction requirements than the ~~overall 60%-70%~~55% RTC reduction proposed for SOx RECLAIM.

Comment #4
There is no evidence to support the assertion that RECLAIM sources have the highest possibility to achieve the 3 ton/day target reduction compared to other SOx sources in the basin. Substantial reductions in SOx emissions have been made from refinery flares but are not properly credited in the 2007 AQMP.

Response #4
Staff acknowledges that significant progress has been made in reducing SOx from refinery flares. However, significant additional reductions are needed above and beyond those committed in the 2007 AQMP to meet the federal and state 24-hour PM2.5 standard. A reduction of 3 tons per day is achievable for SOx RECLAIM facilities taken from the following categories:

- 1.76 tons per day RTC surplus for RECLAIM sources (11.76 tpd available RTC – 10 tpd of 2005 emissions = 1.76 tpd RTC surplus)
- Refinery boilers/heaters can reduce approximately 0.89 tpd reduction to meet Tier I standard applicable since year 2000
- FCCU category alone can reduce approximately 3 tpd reduction estimated from the 2005 emissions baseline.

Contrary to the commenter's observation, the 2007 AQMP properly credited the emissions reduction from the refinery flares in estimating the remaining emissions in future years.

Comment #5
WSPA believes that the BARCT analysis should be conducted on a source category by source category basis per the H&S code requirement and past practice of NOx 2005 RECLAIM shave, not on a facility-by-facility basis as performed by the consultants.

Response #5

BARCT analysis ~~can be~~was done on a source-by-source basis. In addition to that, staff asked the consultants to conduct a facility-by-facility analysis. ~~Although c~~Conducting a detailed facility- and unit-~~-~~specific analysis ~~is~~was very time consuming and not required by the H&S code~~, to the extent such an analysis is possible, it can be highly valuable in helping strike a sensible balance between environmental and economic concerns~~.

Mindful of the implementation costs of control, staff instructed the contractors to conduct facility-by-facility site specific analysis to ensure that the proposed technology can be implemented cost-effectively at each facility. The BARCT analysis (e.g. use a top-down approach in the selection for BARCT, use of discount cash flow (DCF) method in calculating the cost effectiveness factor) was clearly written in the contracts' Statement-of-Work.

There are at least two reasons that make the facility site specific analysis possible for SOx RECLAIM but not for NOx RECLAIM:

- The universe of sources in SOx RECLAIM is much smaller than the universe of sources in NOx RECLAIM. The NOx RECLAIM universe contains hundreds of boilers, heaters, furnaces, and ovens, which makes unit-by-unit analysis impractical.
- The main control technology for NOx in refineries is low NOx burners which can be installed without the analysis of available plot space. The main control technology for SOx sources is a wet gas scrubber for which a unit-specific analysis was needed to assess ~~for~~ available plot space~~ was essential~~.

Comment #6

WSPA believes that a BARCT determination must consider only technologies that are truly "available" and have been proven successful for an adequate period of time in commercial-scale applications. Even the District's definition in Rule 1302(h) (1) of BACT (apparently intended to be more stringent that BARCT) includes the principle of a control technology having been "achieved in practice for such category or class of source"

Response #6

Because BACT is a permitting requirement, it must be achieved in practice to be available at time of permitting. BARCT however can be more stringent than BACT because additional time can be provided to allow technology to mature.

Comment #7

Proposed BARCT emission levels lack proper substantiation (e.g. six months of operation at a certain performance level). This was not done for any of the source categories examined for the refinery. In fact, it cannot be done for the SRU systems proposed as BARCT because none have been used in refineries, much less sulfur plants.

Response #7

A technology does not have to be achieved-in-practice with 6 months of operation at a certain performance level to be defined as BARCT. A technology can be defined as BARCT if it is technologically feasible and cost effective. Wet gas scrubbing technology however is proven achieved-in-practice, and commercially available for refinery FCCUs and SRU/TGTUs.

Comment #8
The cost effectiveness analyses are undermined because they do not include all of the true associated costs, including additional equipment needed to provide additional heat and steam. These gaps have created a significant problem for evaluating potential emission reduction technology applications, their cost effectiveness, and also the logistical applicability to specific facilities. It is inappropriate for the District to make technology recommendations based on incomplete or incorrect data.

Response #8
The consultants have carefully conducted facility and unit specific cost analysis. A contingency factor has been added to cover miscellaneous costs. This procedure is common to all cost estimates. The commenter did not specifically indicate in what applications the additional heat and steam were needed for, so the comment cannot be addressed .

Comment #9
Analyses of plot space requirements were performed 'at the last minute' and were incomplete and did not include equipment required outside the scope of vendor supplied equipment. This example of incomplete analysis and considerations for a "total application solution significantly understates potential costs and cost effectiveness.

Response #9
The commenter has incorrectly characterized the contractors' analysis related to plot space. Plot space analysis was one of the key elements described in the contracts.

The contractors conducted their plot space analysis early on in the project, not at 'the last minute'. As stated in Task #1 of the Statement-of-Work, the contractors were required to conduct field visits at each RECLAIM facility to:

> "assess both <u>physical</u> and operational factors that would impact the feasibility and the cost of additional emission control equipment."

The contractors did not limit their analysis just to the vendor supplied equipment (e.g. wet gas scrubbers) but extended their analysis to cover 'the total application' and they thoroughly discussed the plot space issues with the facilities. As stated in the contractors' reports:

> "Infrastructure items were discussed extensively. These include available areas for a scrubber for the FCCU, room on existing pipe racks, piling, Electrical Substation..….., control systems, steam, water, available sewer allocation….."

Comment #10
The "average cost effectiveness" ratio presented in the staff report is not an appropriate representation of the cost effectiveness of available SOx reduction technologies and has the potential to mislead policy makers. A clear cost-effectiveness threshold should have been established upfront. An incremental cost effective analysis should have been completed to provide a clear relationship between incremental SOx reductions, cost and the associated

emission reduction technology employed. At a minimum, incremental cost effective analysis at 4tpd, 6tpd and 8tpd SOx reductions should be completed to satisfy the following requirements in the State H&S Code.

Response #10
Cost effectiveness factors are process and facility-specific. To present all possible information on cost effectiveness factors to the policy makers and the public, staff has provided four types of cost effectiveness factors in Step 3 of Section 17.2 of Chapter 17 of Part III of the Draft Staff Report:

1. Individual cost effectiveness for a specific emitting source (e.g. cost effectiveness for each FCCU);
2. Average cost effectiveness for the category of source (e.g. average cost effectiveness for five FCCUs in the Basin);
3. Average cost effectiveness for the entire project; and
4. Incremental cost-effectiveness for the entire project

The cost effectiveness factors in this project ranged from $2K to $47K per ton. The individual cost effectiveness factors for each control at each facility (e.g. $14K per ton for Refinery 1's FCCU wet gas scrubber), the average cost effectiveness factor across a class of equipment (e.g. $25K per ton for all FCCUs' wet gas scrubbers); and the average cost effectiveness factor for the entire SOx RECLAIM project (e.g. $17K per ton) were shown in Appendix III-A of the Draft Staff Report.

Staff did not select a clear threshold for cost effectiveness at the time the draft staff report was released. After further consideration, staff selected a cutoff threshold of $50K per ton as a means of removing the least cost-effective control technology recommended by the consultants and optimizing the effectiveness of the most recent staff proposal.

At the time the draft staff report was released, staff estimated the incremental cost effectiveness between the consultant's proposal (Scenario 2: 6.5 tpd) and staff's proposal (Scenario 3: from 6.1 tpd to 6.4 tpd) as shown in Section 18.1 of Chapter 18 of the Draft Staff Report. Even though the overall cost effectiveness of the consultants' proposal was within a reasonable range, the incremental cost effectiveness compared to staff's proposal was significantly large ($300 million per incremental SOx reduced), and because of this reason, staff did not select the consultants' proposals.

Comment #11
There is no evidence in this document that staff considered environmental, energy, economic impacts in any of the proposed scenarios. Until all of these analyses and considerations are completed, making a BARCT determination is premature and arguably invalid.

Response #11
Staff is in the process of conducting additional analysis for environmental, energy and economic impacts to support the proposed BARCT determination in the draft staff report released at the Public Workshop in June 2009.

Comment #12

In all cases, the BARCT recommendations are based on technology forcing emission levels. It is unlikely that under command and control, all of these BARCT proposals would become rules - particularly for those source categories that have only a single facility. It would be more appropriate to have a mix of more and less aggressive levels equivalent to a programmatic BARCT to allow the RECLAIM program to be viable.

Response #12

Staff disagrees with the commenter. Wet gas scrubbing achieving 5 ppmv – 10 ppmv outlet concentrations is not a technology forcing technology. It is a mature, commercially available, and achieved-in-practice technology for many of the affected equipment categories (e.g. FCCUs, SRU/TGs, glass furnace, coke calciner).

For SOx RECLAIM, staff estimated a programmatic RTC reduction of 60%-65%. If AQMD would pursu~~it~~e and "single out" a facility for command-and-control rule, the reduction ~~w~~could be in the neighborhood of 80% - 95% or higher based on the feasibility of wet gas scrubbing technology.

Comment #13

The reliance on guarantee letters provided by the manufacturers is faulty and should not be relied upon to validate or support the emission reduction sustainability.

Response #13

Guarantee letters provided by the manufacturers are only one piece of information that staff relied on to judge the feasibility of the control equipment. In addition to the guarantee letters, staff also relied on achieved-in-practice information, source tests data, CEMS data, and expert consultants' analyses. Furthermore, the sustainability of the emission reductions relies heavily on how the facilities operate and maintain their control equipment. If staff develops command-and-control rules, good engineering practices (e.g. annual maintenance, annual testing) would normally be crafted in the rule requirements to assure continuous compliance with the BARCT levels and guarantee the achievability of emission reductions estimated.

Comment #14

There is no BARCT determination for de-SOx additive, therefore it is inappropriate to consider de-SOx additives as an alternative feasible and available control technology

Response #14

In late August 2008, staff developed a testing protocol for de-SOx catalysts with the participation of WSPA and the refineries. Only one of the refineries volunteered to participate in the short-term source testing from September 2008 – November 2008. From this short-term testing, this refinery was able to achieve approximately 7 ppmv SOx at 0% O2 and at the same time also met the PM10 emission level in Rule 1105.1.

Comment #15

Several data requests have been made of the SCAQMD: 1) clarification of how certain emission factors (starting and new) for FCC's, SRU's and boilers were derived for individual facility process units, 2) facility specific data/calculations be sent directly to the six individual WSPA member facilities, 3) derivation of the emission factors referenced in Appendix III-A of the Staff Report SOX RECLAIM Part III, and 4) 1997/2002/2005 baseline.

Response #15
The following information was provided to WSPA and the refineries:

- Clarification of how certain emission factors (starting and new) for FCC's, SRU's and boilers were derived for individual facility process units was explained and provided in the Working Group meetings on July 30, August 13, and August 27, 2009
- Derivation of the emission factors referenced in Appendix III-A of the Staff Report SOX RECLAIM Part III was explained and provided in the Working Group meetings on July 30, August 13, and August 27, 2009
- Facility specific data/calculations were e-mailed directly to the six individual WSPA member facilities on July 17, 2009
- The 1997 and 2005 baselines were presented in the Staff Report released at the June 2009 Public Workshop. Staff did not ~~see the benefit of providing~~provide the 2002 baseline, because there was no demonstrated need for that baseline.

- **Water & Wastewater**

Comment #16
There is no information regarding the total water related impacts of the dozen potential scrubber installations. The report provides a broad impact: for fresh water – between 1 and 90 million gallons per year for each scrubber, and for waste water – between 1 and 40 million gallons per year for each scrubber. Thus, the total impact could be as high as one billion gallons per year of fresh water (90 million gallons and 12 installations), and an increased wastewater load to Publicly Owned Treatment Plants (POTWs) as high as 440 million gallons per year (40 million gallons and an assumed eleven systems that would discharge to a POTW).

Response #16
The above estimated water usage and wastewater generated provided by the commenter (1 billion gallons per year water usage and 40 million gallons waste water generated) are incorrect.[71]

In July 2009, staff developed a Survey Questionnaire to gather information on the current usage of water, the current amount of wastewater and solid waste generated, and the existing practice (e.g. ground water capacity and current pumping rate, recycled water usage) at the 11 top emitting facilities. The facility's responses to staff's Survey Questionnaire are summarized in

[71] The reported water usage and waste water generated for the SRU//TGTUs' scrubbers estimated by the consultants in their final reports were ~~incorrect~~not the same as estimated in the draft staff report. Perhaps, there was a typo in the figures (e.g. misplacing the decimal point). Staff has revised these figures based on the numbers provided by the wet gas scrubbers' manufacturers.

Table XX, Chapter XX of the Staff Report. Based on the facility's responses, the impacts of the project on water and waste water are as follows:

- The total current water usage for the 11 facilities is 18,842 million gallons per year. This project would require 364 million gallons water per year. This impact reflects an estimated 2% increase in water demand from these facilities relative to their current water usage.

- The total current wastewater discharged by the 11 facilities is 10,556 million gallons per year. This project would generate about 160 million gallons per year, or about 1.5% increase in wastewater generated from these facilities relative to their current wastewater discharge.

Comment #17
The consultants admitted that there are a number of disadvantages to wet gas scrubbing: 1) Fresh reagent and fresh water must be fed to the unit to replace the water lost as waste water and the reagent consumed in the reaction, 2) The reaction products are generally salts that must be carried away with a waste water stream, 3) Sodium sulfite and sodium bisulfite salts are created and these salts increase the chemical oxygen demand (COD) of the waste water, 4) A large visible plume usually forms as water is evaporated, which is an aesthetic concern and constitutes a loss of water for the refinery.

Response #17
Wet gas scrubbing technology is a mature technology. As any other control technology, wet gas scrubbing also has its own advantages as well as disadvantages. Regardless of the disadvantages cited, many facilities in the U.S. and in the District have chosen to install and successfully operate wet gas scrubbers to control SOx and particulate matter from various types of stationary sources. Clearly, those facilities believe the advantages of the technology outweigh any disadvantages. As written in the Module 3A report, the consultants objectively commented on both the advantages and disadvantages of wet gas scrubbers and cited the following advantages:

> "*There are a number of advantages to wet gas scrubbing. Operation of the package is not particularly complex, and the process hazards that accompany it are typically manageable in a refining environment. In addition, such units are very effective at removing SOx $_{from}$ gas streams and can also reduce emissions of particulate matter into the air.*"

- **Fluid Catalytic Cracking Units, SRU/TGTUs, Boilers/Heaters**

Comment #18
There are no records to support the performance of the wet gas scrubber on the FCCU at the Valero Delaware City Refinery.

Response #18
The Delaware Department of Natural Resources and Environmental Control (DNREC) provided staff with approximately 18-months 1-hour CEMS data (a total of 10,386 records). The average concentration of this 18-months period of operation was 1.2 ppmv at 0% O2, well below the proposed BARCT level of 5 pmv. In addition, there is a wet gas scrubber installed and operated

at a refinery in the District since August 2008. The performance of this wet gas scrubber (i.e. mass emissions from CEMS for a period of 265 days and a performance source test result) was listed in Appendix III-D of the draft Staff Report.

Comment #19
It is inappropriate for the consultants to make a BARCT recommendation.

Response #19
Staff did not view the consultants' action as inappropriate. As shown in the Statement of Work, the consultants were required to present various levels of feasibility and estimate the emission reductions and cost effectiveness at each level. They indicated in their report that wet gas scrubbing technology could achieve a level as low as 1 ppmv and they provided emission reductions and cost effectiveness associated with this level as required by the contract. However, they also concluded that a level of 5 ppmv is more realistic to implement. Therefore, they recommended that level be BARCT even though they were not required to do so by the contract. This is only a recommendation and should not be viewed as inappropriate. During the process of formulating its final BARCT proposal, staff will review, verify and use all technical information provided by the consultants as well as information from other sources. Staff is ultimately responsible to make a final BARCT recommendation to the Governing Board for its consideration, and the Governing Board will ultimately make a final decision on what are the appropriate BARCT levels.

Comment #20
In the report, the contractors stated that "... it is the recommendation of the ETS team that non-regenerative wet scrubbing be considered on a purely technical basis (emphasis added) as BARCT ...with an overall BARCT level of 5 ppmv." It is apparent, that the contractor made their unauthorized recommendation solely on a technical basis, and therefore it is not a defensible BARCT determination.

Response #20
The consultants' recommendation was not purely based on technical information. The consultants conducted a detailed engineering evaluation and cost analysis assessment strictly adhered to the Statement of Work:

> *".....visit each of the six local refineries in the Basin to gather site specific information (e.g. operating conditions) and to conduct site-specific feasibility assessment analysis....evaluate the existing commercially viable control technologies, starting with the most effective control technology, and make recommendations to the District on various technologies that could potentially be used to achieve additional emission reductions, on various concentration targets that could be achieved with each technology, the estimated emission reductions, the multimedia pollutant impacts (e.g. water, waste), energy impacts of the technologies, and the associated cost effectiveness associated with the control technology."*

On a purely technical basis, the consultants recommended a level as stringent as 1 ppmv. However, after carefully considering costs and other impacts, the consultants recommended a level of 5 ppmv for FCCUs with the use of wet gas scrubbing technology, 5 ppmv for SRU/TGTUs with wet gas scrubbing technology or oxidation catalysts, and 40 ppmv for boilers/heaters with various types of fuel gas treatment techniques. As mentioned in previous responses, in formulating its BARCT proposal, staff carefully evaluated the consultants' recommendations and introduced several refinements to improve and optimize the effectiveness of staff proposal.

Comment #21

The contractors claimed that it was impossible to address every one of the individual cases and therefore the team made use of generic, but representative quotations and published cost studies. Because there are only five FCCUs in the Basin, and because the estimated present worth of implementing the proposal for FCCUs alone is $493 million, it is a flawed practice to attempt to use a "generic" approach.

Response #21

The consultants did not use a "generic" approach to estimate the total costs of $493 million for FCCUs' wet gas scrubbers. As required under the Statement of Work, the consultants conducted site specific analysis for each FCCU at the six refineries and gathered costs information for each individual FCCUs from the manufacturers. As shown in the final report of Module 3A, the consultants included the following items in their cost estimation:

- Categorized costs include:
  - Demolition and decommissioning
  - Civil/concrete
  - Structure
  - Equipment
  - Piping and Mechanical
  - Electrical and controls
- Miscellaneous line items include:
  - Contractor overhead, typically 8 % of direct field labor (DFL)
  - Contractor field supervision, typically 12 % of DFL
  - Mobilization/demobilization, typically 10 % of DFL
  - Overtime/productivity factor, typically 12 % of DFL
  - Freight and shipping, typically 8 %, of materials
  - Sales tax, typically 7 % of materials
  - Commissioning and operating spares, typically 5 % of materials
  - Startup/initial fill material, typically 2 % of materials
  - On-site training/startup assistance, depends on project
  - Front-end engineering design, depends on project size
  - Project management, depends on project size
  - Design development allowance, 10% of total
  - Contingency, 25-40% applied against the bottom-line capital cost estimate

The "generic" approach that the consultants followed was the Discounted Cash Flow (DCF) methodology provided by SCAQMD staff to estimate the cost effectiveness factor. This cost effectiveness methodology is consistently used in the AQMPs and in all the rules and regulations developed by the SCAQMD.

Comment #22

Adequate consideration needs to be given for plot space concerns.

Response #22

Plot space concerns were addressed in the consultants' report, section H:

> "Wet gas scrubber equipment footprints and space requirements for the FCCUs and the SRU/TGTUs are shown in the confidential appendices for each refinery where measures have been selected. These specifications have been compared with the plot plans provided by the respective refineries, and where applicable, are presented in the costing workbooks."

Comment #23

Regarding Emerachem technology, the fact that the precious metal (presumably a platinum group metal) can be reclaimed at the end of the useful life of the catalyst does not in any way suggest that this is an "investment". Reclaiming the metal is a significant cost and the reclaimed material only exists as a partial "credit" against the purchase of fresh catalyst. The initial purchase price of the metal is only actually recovered when the plant is shut down for good, and the value of the metal can be higher or lower than the original purchase price.

Response #23

Staff is not clear on the term "investment" used by the commenter and is not certain about the purpose of the comment. In Measure M13, the costs to purchase the fresh catalyst system ($1,800,000) are included in the quote from Emerachem. The consultants also included the costs for catalyst change ($420,000) quoted by Emerachem. The consultants gave a salvage value (credit) of merely $50,000 to the Emerachem control system at the end of the equipment life. In lieu of Emerachem, the facility may select to install a wet gas scrubber. In Measure M17, a wet gas scrubber would initially cost approximately $5 million but has a salvage value of $300,000. (Measure M13 and Measure M17 were not to control the same SRU/TG however the costs cited above can only be used qualitatively)~~Emerachem is an alternative control technology. The regulated industry may choose another method to reduce SOx emissions. However, some facilities may choose this control technology.~~

Comment #24

Project timing estimates made by the contractor do not reflect realistic logistical and/or market pressures resulting from multiple refineries and other industries pursuing similar technologies during a closely concurrent timeline.

Response #24

Such timing estimates will be given further consideration as part of the staff analysis.

Comment #25
Inadequate information to substantiate the 5 – 10 ppm performance of the wet gas scrubbers designed for the SRUs/TGTUs. The lack of substantiation beyond the vendor sales literature is highly questionable.

Response #25
Staff recently received the most recent CEMS data (6 months of 1 hour average data) from the Wyoming Department of Environmental Quality which indicated that the DynaWave wet gas scrubbers installed and operated since 2004 at Sinclair Refinery in Wyoming can achieve the performance levels recommended by staff.

Comment #26
The cost effectiveness for this source category (SRU/TG) is on average high (> 30k$/ton) in comparison to the FCCU source category and appears to include higher variability, making a comprehensive review all that more important. WSPA requested and did not receive specific data used by the consultants to arrive at the cost effective conclusions reported. In some cases it appears that the technology vendor has provided promises of very high control efficiency and what appear to be artificially low capital cost estimates – all at no risk whatsoever to themselves. This is particularly true of this source category where the proposed BARCT vendors have no experience
with installation in refineries, which makes their cost estimates highly suspect.

Response #26
Staff has recently removed the emission reductions and associated costs for Refinery #4 and #5 because of the unfavorable cost effectiveness (>$50K per ton). The cost data and performance levels proposed by the consultants for the wet gas scrubbers for Refinery #2 and #6 are reliable, substantiated by the achieved-in-practice performance of the wet gas scrubbers at Sinclair refinery in Wyoming. Staff currently does not have any achieved-in-practice data from Emerachem catalysts technology for Refinery #3 but Emerachem provided the consultants with a guarantee letter and the consultants also considered a wet gas scrubber for Refinery #3 in their confidential analysis.

Comment #27
WSPA would agree that the proposal to maintain the existing 40 ppm limit on the sulfur content of fuel gas is appropriate. Further WSPA notes that the current US-EPA New Source Performance Standard (adopted in April 2008) has a limit that is approximately four times higher.

Response #27
Staff appreciates the comment and continues to maintain that the 40 ppm on the sulfur content of fuel gas is appropriate.

Responses to Chevron's Comments Received on July 14, 2009

Comment #1
It is inappropriate for the District to aggressively pursue SOx shave for PM2.5 attainment. The current trend of PM2.5 is declining and does not warrant a SOx shave that is estimated to cost industry over one billion dollars.

Response #1
For a market based incentive program, staff is required by the H&S codes to conduct periodic BARCT reassessment and demonstrate equivalency with command-and-control rules which would otherwise be developed as a result of BARCT reassessment:

> *"…achieve an equivalent or greater level of emission reductions at an equivalent or lower cost as would have been achieved under a command-and-control rule"*

It should be noted that SOx is a significant building block of PM2.5. Chemical speciation of PM2.5 samples indicated that in the South Coast Air Basin 25% of the ambient PM2.5 is attributed to contribution from sulfates. Furthermore, SOx reductions are highly effective in reducing ambient PM2.5 levels as compared to other primary and secondary contributors to PM2.5 formation (1 tons SOx = 1.5 tons PM2.5 = 15 tons NOx). Therefore, the reductions of SOx are essential for the basin to meet the federal annual standard of PM2.5 by 2015 and the federal 24-hour average standard of PM2.5 by 2020. As indicated in the 2007 AQMP, the control strategies included in the Plan to meet the annual PM2.5 standard when fully implemented will fall short meeting the 24-hour standard by approximately 30%. Therefore, additional reductions above and beyond the control strategies committed in the 2007 AQMP for meeting the 2015 annual PM2.5 standard are necessary to meet the 24-hour PM2.5 standard in 2020. For further information, please refer to Chapter 5 of the 2007 AQMP.

In addition, it is worth mentioning that the U.S. EPA is proposing to set a new, more stringent, one-hour standard for SO2 between 50 – 100 parts per billion (ppb) and revoke the current 24-hour of 140 ppb and the current annual standard of 30 ppb to further protect public health.

In addition, the percent reduction in RTCs (60%-65% prior to January 2010, currently revised to 55%) that staff estimated for the SOx RECLAIM universe as a whole is still much less stringent than the percent reduction in emissions (90% - 98%) that staff could impose to specific categories of sources such as FCCUs, SRU/TGs, sulfuric acid plant, cement plant, coal fired boiler, and glass melting furnaces if staff pursues the command-and-control approach.

Staff however is sensitive to the costs of the current proposal (approximately $745 million). To reduce the cost impacts, staff proposes to spread the potential emission reductions into 6 years starting from 2012. Staff also proposes to submit only 3 tons per day reductions to satisfy the SIP commitment in Phase 1 (i.e. 3 tpd reductions by 2014). The remaining reductions will be submitted later.

Comment #2

Staff proposal does not reflect a comprehensive environmental impact. A negative impact to other environmental media such as water and waste were not discussed. Capital investment to manage additional volumes of water demand, wastewater and solid waste generated were not included. In addition, the proposal did not include the complexities of attaining necessary permits (e.g. NPDES Discharge Permit.)

Response #2

Staff is in the process of analyzing the environmental impact for this proposal. In July 2009, staff sent a Survey Questionnaire to the effected facilities to gather information on current usage of water, wastewater and solid waste generated. A summary of the information received was presented to the stakeholders in the August 2009 Working Group Meeting (please see Table 11-1 in the revised draft staff report).

In general, there will be an increase in total water demand (264 million gallons per year, or less than 1 million gallons per day, for all six refineries)[72] due to the proposed control technologies. On a relative scale, however the increase however will be small (below 2%) compared to the current total water usage at the refineries (16,936 million gallons per year, or 46 million gallons per day). Ground water pumping capacity is available for four out of six refineries. Three out of six refineries have used recycled water. All 6 refineries are not subject to any cap from the water suppliers. The water suppliers indicated to staff that they can supply the additional amount of water to the refineries. In addition, the increase in total water demand is 80% below the current CEQA threshold of 5 million gallons per day for significance.~~, and the increase of potable water demand is within a less than significant CEQA threshold. Therefore, staff believes that the water impacts due to this proposal are less than significant.~~ However, in a spirit of taking abundance of caution, CEQA staff classified this project as significant in terms of potable water demand. Please refer to the Program Environmental Assessment for further explanation.

This proposal will generate an additional amount of wastewater ranging from 15 – 50 gallons per minute, (or a total of 94 million gallons per year at 6 refineries). The increase in wastewater discharge will be small (less than 1%) compared to the current discharge at each refinery which varies from 1,000 – 5,000 gpm. Typically, an increase in wastewater discharge in excess of 25% would trigger a discharge permit revision. However, since the increase in wastewater discharge is significantly less than 25%, the refineries will not need to revise their NPDES discharge permits. Staff also believes that the refineries can handle this amount of increase in their current wastewater treatment system. Therefore, the impacts on wastewater are less than significant.

This proposal will generate an additional amount of solid waste depending on how effectively the scrubbers are in controlling particulate matters. The consultants estimated about 2,560 tons per year increase. The current FCCU fines classified as non-hazardous waste generated from the six refineries are approximately 3,348 tons per year. This 67% increase may be trucked to several cement facilities in and around the basin (CPCC in Colton, CEMEX in Victorville, TXI-

[72] In August 2009, staff revised the water demand reported by the consultants for the SRUs/TGTUs using the information submitted directly by the manufacturers of the wet gas scrubbers.

Riverside in Oro Grande, National Cement in Kern County, CPCC in Mohave Desert, and Lehigh in Tehachapi).

As shown in the consultants' report, and as quoted below, the consultants did included~~d~~ additional capital costs for waste and wastewater treatment. In addition, the consultants did included~~d~~ additional annual operating costs for additional water, wastewater treatment, and solid waste disposal.

> *"Added charges for waste or wastewater treatment equipment are included in equipment costs unless treatment is performed outside of the boundary limits for the control measure. In these cases, the treatment costs have been calculated according to the treatment requirements and site-specific unit costs provided by the refineries."*

Comment #3
Emerachem technology is not a proven technology. The contractor report does not offer any strategy for dealing with the concentrated SO2 stream captured and released later from the catalysts, therefore this technology cannot be considered as SOx reduction technology.

Response #3
It is true that Emerachem technology has not yet been installed and used in a refinery, and therefore there is no achieved-in-practice data available. However, this ~~is not a strong~~ argument does not negate~~s~~ the feasibility of this technology in a refinery application. For BARCT, additional time can be provided to allow technology to mature in refinery applications. Furthermore, in addition to the Emerachem technology, the consultants provided three additional options to reduce the SOx emissions from the three SRU/TGTUs at this refinery that reflect achieved-in-practice technologies. In summary:

- Emerachem technology resulted in about 53 tons/year reduction for SRU#10 and SRU#20 and a cost effectiveness of $13K per ton,
- Wet gas scrubbing resulted in about 41 - 44 tons/year reduction for SRU #70 and a cost effectiveness of $32K per ton - $45K per ton (data from 2 WGS vendors were considered),
- Additional 3rd stage Claus units resulted in about 20 tons/year reduction for SRU#10 and SRU#20 and a cost effectiveness of $24K per ton.

If for the sake of an argument, the current scenario (Emerachem for SRU#10 and SRU#20) is replaced with other scenarios (3rd Claus units for SRU#10 and SRU#20 & WGS for SRU#70), it will result in 64 tons per year reductions instead of 53 tons per year reductions at a cost effectiveness of approximately $30K per ton. Implementation of these scenarios will not significantly change the overall cost effectiveness of the proposed overall program.

Comment #4
The shave methodology was not transparent, was disclosed very late in the process, and did not appear to be consistent with the 2005 NOx shave.

Response #4
Staff followed recommendations by WSPA and WSPA members to stay consistent with the NOx shave methodology that was developed by the District's staff and agreed upon by WSPA and WSPA's members in 2005. However, there is no requirement to do so.

While there is an agreement in principal to stay consistent with the 2005 NOx shave methodology, developing an actual shave methodology that will work for the SOx RECLAIM market and is fair and equitable is not a trivial task. To use the 2005 NOx shave methodology, staff invested tremendous amount of time and effort to recover the 1997-1998 emissions baseline and the starting emission factors in 1993. Using the 1997-1998 emissions baseline and the 1993 starting emission factors, staff estimated the control factors and RTC reductions as shown in Part III of the Draft Staff Report presented in the June 9, 2009 Public Workshop. The RTC reductions presented in the June 2009 Staff Report (i.e. 7.09 tpd – 7.68 tpd) were very similar to the emission reductions estimated by staff in April 2008 (i.e. 6.73 tpd – 6.77 tpd) based on the 2005 emission inventory baseline. Staff expects the proposed shave methodology to continue being refined throughout the rule making process.

It should also be noted that the shave methodology was disclosed sooner than in the NOx RECLAIM rulemaking effort in 2004-2005.

Comment #5
The methodology for development of emission factors was not clear in the report, and the background for some of the initial emission factors was not clearly explained.

Response #5
The following information was provided to WSPA and the refineries:

- Clarification of how certain emission factors (starting and new) for FCC's, SRU's and boilers were derived for individual facility process units was explained and provided in the Working Group meetings on July 30, August 13, and August 27, 2009
- Derivation of the emission factors referenced in Appendix III-A of the Staff Report SOX RECLAIM Part III was explained and provided in the Working Group meetings on July 30, August 13, and August 27, 2009
- Facility specific data/calculations were e-mailed directly to the six individual WSPA member facilities on July 17, 2009.
- Staff is always available for additional explanation.

Responses to Tesoro's Comments Received on July 14, 2009

Comment #1
The current proposal goes far beyond what is called for in the AQMP.

Response #1
In addition to the 3 tons per day reduction by 2014 SIP commitment stated in the 2007 AQMP, for a market based incentive program such as RECLAIM, staff is required by the H&S codes to conduct periodic BARCT reassessment and demonstrate equivalency with command-and-control rules which would otherwise be developed as a result of BARCT reassessment:

> *"…achieve an equivalent or greater level of emission reductions at an equivalent or lower cost as would have been achieved under a command-and-control rule"*

As a result of this BARCT reassessment and equivalency demonstration, staff estimates that the SOx RECLAIM program can be amended to provide 6.2 tons per day emissions reduction (or approximately 64% of RTC reductions)

Comment #2
The process for determining BARCT was not well defined. The consultants BARCT determinations appear to be generally based on vendor guarantees. The reports do not contain adequate information to substantiate the BARCT emission limits that are proposed for each source category.

Response #2
The consultants and staff followed the BARCT selection process outlined in Part III of the Staff Report. The BARCT selection process include~~s~~d five steps: 1) identify technology that can achieve maximum degree of reduction, 2) evaluate control effectiveness, 3) conduct a top-down cost analysis, 4) conduct an impact analysis for environment, energy and economic, and 5) select BARCT. Vendor guarantees are important information for Step 2. In evaluating the consultants' recommendation for BARCT and arriving at the staff proposal for BARCT, in addition to vendor guarantees, staff relied on source test data, CEMS data, permitting data, and engineering evaluation. Staff believes that adequate information have been provided to substantiate the proposed BARCT for all source categories.

Comment #3
An analysis of the impact of the proposed shave on the RECLAIM market has not been conducted. Because of the potentially dramatic impact that this shave will have on the RECLAIM SOx market, Tesoro supports a phased approach to the SOx shave. Since the 2007 AQMP did not analyze for attainment with the PM2.5 24-hour standard, we recommend that further analysis be completed during the PM2.5 Plan Update to determine if additional tons are needed for the 2020 attainment.

Response #3

Additional reductions in SOx emissions beyond and above those committed in the 2007 AQMP are needed to meet the federal 24-hour PM2.5 standard in 2020. Although the District has not yet developed the control strategies for the 24-hour PM2.5 standard, it analyzed the input of the standard as part of the 2007 AQMP. This analysis revealed that the PM2.5 control strategies included in the 2007 AQMP will fall short by 30% in meeting the PM2.5 24-hour standard. Staff is in the process of conducting a market analysis for the SOx RECLAIM program. To reduce the impacts to the SOx market, staff is in agreement with Tesoro and proposes to phase in the proposed reduction beginning 2012 through 2017. Staff further proposes that at least 3 tons per day of the reductions be phased in by 2014 to meet the SIP, and the remaining emission reductions submitted into the SIP at a later date.

Comment #4

The costs for implementing the chosen technologies are not adequately considered in the consultant reports or in the Staff reports. The report bundles all the measures into an "average cost effectiveness" ratio. This "average cost effectiveness" ratio is not an appropriate representation of the true cost of the SOx reduction technologies and is misleading.

Response #4

Please refer to Response #10 to WSPA's comment letter received on July 14, 2009

Comment #5

There is a significant increase in water demand, wastewater discharge levels and hazardous waste generation resulting from use of wet gas scrubber technology. Further analysis of these significant environmental impacts should be conducted in the BARCT evaluation.

Response #5

Please see Response #2 to Chevron's comment letter received on July 14, 2009

Comment #6

There are a number of unanswered questions concerning the origin of certain assumptions and numbers used to calculate the current BARCT numbers and shave recommendations.

Response #6

The answers were provided to WSPA and the refineries in the Working Group meetings on July 30 and August7. Refinery specific data were e-mailed to each refinery on July 17, 2009. Staff is always available if further explanations are needed. A summary is provided below:

Derivation of the starting emission factors

FCCUs

Starting emission factor = Total emissions (lbs/year) / Total throughput (barrels/year)
= (6,033,327 lbs/year) / (115,893 thousand barrels refinery feed) = 52.06 lbs/Mbarrels

Sulfur Recovery Units

Starting emission factor = Total emissions (lbs/year) / Total hours operation (hours/year)
= (1,122,050 lbs/year) / (133,764 hours/year) = 8.39 lbs/hrs

Boilers/Heaters

Starting emission factor = Total emissions (lbs/year) / Total fuel usage (mmscft refinery gas/year)

= (3,738,879 lbs/year) / (112,105 mmscft/year) = 33.35 lbs/mmscft

Derivation of the proposed new BARCT level for FCCUs

Consultants' proposed level:

Remaining emissions = 3.52 – (0.58+0.19+0.28+0.20+0.87+0.94) = 3.52–3.07 = 0.45 tpd

Emission rate = (0.45 tpd x 2000 lbs/ton)/(396 thousand barrels feed/day)

= 2.27 lbs/thousand barrels

Staff's proposed level:

Remaining emissions = 3.52 – (0.58+0.28+0.20+0.87+0.94) = 3.52–2.88 = 0.64 tpd

Emission rate = (0.64 tpd x 2000 lbs/ton)/(396 thousand barrels feed/day)

= 3.25 lbs/thousand barrels

Derivation of Tier I factor for heaters and boilers

Tier I factor for boilers and heaters (external combustion Equip/Incinerator using refinery gas) is on Table 2 of Rule 2002 = 6.76 lbs/mmcf = 40 ppmv

Why is the remaining inventory for heaters and boilers different in Part I and Part III of the staff report (1.42 tpd vs. 0.89 tpd)?

The Tier I allocations shown in Table 4-1, Part I of the Staff Report (0.89 tons per day) were for 6 refineries in the basin. The remaining inventory shown in Appendix III-B, Part III of the Staff Report (1.42 tons per day) were derived from the 1997-1998 inventory of all boilers/heaters at all active refineries in 1997-1998.

Responses to BP's Comments Received on July 14, 2009

Since BP requested the opportunity to review and highlight the comments for confidentiality before the comments are printed in public document, staff will not print BP's comments or responses to BP's comments at this time.

Responses to Paramount's Comments Received on July 14, 2009

Comment #1

Unlike the NOx universe, the SOx universe is small enough that the District could come up with a plan for the SOx shave that would take into account the technology employed and individual opportunities for SOx reductions that are available at different facilities. For the rule to be equitable, only facilities that operate certain source categories and do not yet meet the BARCT standard should be required to take the BARCT adjustment. Facilities that do not operate FCCUs should not be responsible for emission reductions from FCCUs.

Response #1

Staff is in agreement with the commenter. The SOx market is very different than the NOx market. Eleven facilities in the SOx market are responsible for 94% of the emissions and hold about 86% of the RECLAIM Trading Credits. The preliminary draft Staff Report released in 2008 focused in finding BARCT and emission reductions from the top eleven facilities and seven categories of sources. It would be difficult for a facility with no equipment subject to new BARCT to reduce SOx emissions. Staff is examining two alternatives: 1) provide an alternative percent shave for these facilities, or 2) not shave these facilities at all. For facilities that have the 2012 RTC holdings higher than the 2012 initial allocations provided to the facilities at the start of the RECLAIM program, staff may shave the surplus up to the 2012 initial allocations. Further discussions are needed to finalize the proposal.

Comment #2

The implementation for the District's proposal can take 3 years to complete, yet the District scheduled for implementing the SOx shave starts with reductions in 2012, which is only 2 years from the planned adoption date. Refineries must make modifications during turnarounds that typically occur every 3 – 5 years. The implementation date should be moved back to 2014 to enable facilities time to pursue these major modifications

Response #2

Staff proposed a first shave of 1.5 tpd at the end of compliance year 2012. This 1.5 tpd comes from the surplus RTC (Total RTC holdings = 11.7 tpd & actual emissions = 10 tpd). Wet gas scrubbers may take may take up to three years to install, therefore staff proposed a second shave of 1.5 tpd at the end of compliance year 2013. The remaining shave was proposed to be distributed in additional four years from 2014 to 2017.

Comment #3
Paramount has been significantly left out of recent developments in this rule making process. Paramount did not have an opportunity to participate in the consultants' study and evaluated the findings along with major refiners. Paramount suggests that a concerted outreach effort be conducted to ensure that all impacted facilities are given the opportunity to understand and comment on the District's SOx shave proposal.

Response #3
The recent developments were all ~~notice~~ publicly notice. The Request-for-Proposals was also posted on the District's web site. Staff conducted a bidder's conference on July 16, 2008 which was posted on District's web site. Staff's recommendations were presented to the Governing Board at two public meetings on July 11, 2008 and September 5, 2008. There are subsequent public consultation meetings, workshops, and working group meetings held where the consultants' recommendations and suggested amended proposals were further discussed. There were ample opportunities for the commenter to participate. However, staff did not receive any comments, suggestions, or indications of interest from the commenter during this period of time until after the consultants' study was finalized. In addition, it should be noted that most of the information and analysis was conducted on a facility-by-facility confidential basis and cannot be discussed with the commenter. Staff did send copies of the consultants' non-confidential reports to the commenter as requested on September 2, 2009.

Responses to WSPA's Comments Received on July 2, 2008

Western States Petroleum Association
Credible Solutions • Responsive Service • Since 1907

Jodie Muller
Manager, External Affairs and South Coast Region

July 2, 2008 Via E-Mail and First-Class Mail

Joe Cassmassi
South Coast Air Quality Management District
21865 East Copley Drive
Diamond Bar, CA 91765-4182

WSPA Comments on the Preliminary Draft Part I Staff Report - RECLAIM SOx

WSPA appreciates the opportunity to comment on the "Preliminary Draft Staff Report Sox RECLAIM Part I Allocations, Emissions & Control Technologies" (the "Report"), and we appreciate your patience while we were addressing the other priorities that you had established (e.g., the RFP for the contractor project, FCCU SOx reduction catalyst additives, etc.). WSPA's detailed comments are attached to this transmittal email, in the form of comments and suggested edits provided directly on the draft Staff Report.

WSPA's attached detailed comments speak for themselves, and we need not summarize them in this transmittal. However, there are a few overarching issues that we would like to specifically call to your attention:

Comment #1

1. The draft Report references 2007 AQMP Control Measure CMB-02 as being the impetus for the BARCT reassessment, but the Report does not accurately describe the legal basis for this rulemaking effort, nor does it address the process by which the BARCT reassessment will be conducted. While the Report provides an overview of existing control technologies and suggests new, potentially feasible emission rates or limits, it does not provide detail regarding the process the District will use to identify new 2010 facility annual allocations, does not indicate how the District will determine the feasible reductions to be achieved by the "shave", and does not address the need for a reasonable compliance margin.

An understanding of, and agreement with, the methodology for developing BARCT levels, and the resultant potential shave, needs to precede most of the other work. The facilities that will be subject to any SOx shave need to know exactly how proposed revised allocations and the proposed shave will be calculated. Only once the process has been agreed to should the District move ahead with reassessing the BARCT levels.

Comment # 2

2. The report alludes to the possibility of incorporating both the reassessment of the BARCT levels under the SOx RECLAIM program (as proposed in 2007 AQMP CM CMB-02) and the concept of facility modernization (from 2007 AQMP CM MCS-01) into a combined overall effort to reduce SOx emissions. However, the Report does not explain the process for doing so or why it might be appropriate to include a facility modernization analysis with this effort. WSPA is concerned about the potential for blurring the distinction between a BARCT reassessment and the possibly similar assessment of facility modernization. Since there will likely be overlapping issues, it is very important that the District independently develop, and reach consensus on, the process for implementing each control measure. If both measures are to be considered simultaneously, then the Report must clearly show how each measure will work in tandem with the other (and the feasibility of such an approach) before allocation levels are established.

Comment #3

3. The Report attempts to tie the potential reduction of RECLAIM SOx allocations (i.e., a reduction of SOx emissions) to PM air quality but does not establish the necessary basis for a linkage between the two. The Report cannot be based on an assumed relationship between SOx emissions and ambient PM_{10} or $PM_{2.5}$ levels; rather, it must describe and provide evidence for how SOx emissions contribute to ambient particulate matter concentrations and how the anticipated SOx emission reductions will affect ambient air quality.

Comment #4

4. The "Proposed BARCT Levels and Emission Reductions" section of chapters three through nine includes detailed conclusions with respect to the applicability of various emission control technologies and the resultant BARCT levels for the various source categories in the SOx RECLAIM program. These conclusions are premature and unsubstantiated, and their inclusion in the report is not appropriate given that the District is planning to hire one or more expert third-party contractor(s) to conduct thorough engineering evaluations and cost estimates of potential SOx emission reduction technologies. WSPA is very concerned that the Report's preliminary, and largely unsubstantiated, conclusions will become benchmarks against which the contractors' work products might be evaluated and effectively prejudge the expected conclusions rather than foster an independent analysis.

Comment #5

5. Due to the significance of this SOx BARCT reassessment program and the issues that we have identified with the draft Report, WSPA believes that the Report must be substantially re-written. The issues WSPA raises here and in the attached detailed comments cannot (and should not) be handled though responses to comments or preparation of a supplement Report, either of which would require the reader to read and understand two or more separate and likely conflicting documents. WSPA has tried to present its detailed comments in a way that can serve as a useful guide for rewriting the draft Part I Report, and hopes that District staff take advantage of our suggestions in that manner.

Again, WSPA appreciates the opportunity to submit these comments on this important effort. We ask that our detailed comments and this transmittal letter be included in the record for this rulemaking. WSPA looks forward to working with the District as this effort progresses, and we look forward to commenting on future drafts of the Part I and Part II Staff Reports for this rulemaking, as well as on any proposed rule amendments and other related regulatory materials.

Please do not hesitate to contact me if you have any questions.

Sincerely,

Jodie Muller
Enclosure -- WSPA Comments
cc: Gary Quinn, P.E.
Laki Tisopulos, Ph.D., P.E.
Minh Pham, M.S., P.E.

Staff's Responses to WSPA's Comments

Response #1

Staff appreciates WSPA's comments and suggested edits on Part I of the Preliminary Draft Staff Report. Staff will respond to all WSPA's comments, review WSPA's edits, and if appropriate, will revise the Draft Staff Report.

Regarding WSPA's detailed comments, staff will respond to the key issues and retain the detailed comments in the Administrative Records of this amended rule. This approach is taken to reduce the bulk of the detailed comments/responses portion of the Draft Staff Report.

First, staff would like to direct WSPA to the legal basis of this rule making effort described in Section 1.1 of the Draft Staff Report – Legislative Authority. Secondly, with all due respect, staff disagrees with the sequence of approaches recommended by WSPA for this rule amendment. Staff 's seven-step approach for this rule amendment is described below, in sequence:

1. Conduct an assessment of allocations and emission baselines;
2. Conduct a review of control technologies;
3. Identify areas of potential emission reductions, focusing on these areas with greatest potential reductions;
4. Conduct site-specific evaluation of control technology feasibility and costs
5. Assess BARCT
6. Re-examine the potential emission reductions in Step 3, taking into consideration the final emission reductions, and the amount of allocation shave while maintaining the integrity, equity, and operational characteristics of the SOx RECLAIM program; and
7. Amend appropriate rules in Regulation XX.

The first three steps were presented in Part I of the Preliminary Draft Staff Report and several of staff's presentations at the SOx RECLAIM Working Group Meetings. The last four steps are presented in Part II of the Draft Staff Report, and will be developed in parallel with the contractors' work on the proposals

Response #2

For this rule amendment, BARCT reassessment will be the basis that used to assess the emission reductions and the allocation shaves. The concept of facility modernization, if used, may only influence the timing of the allocation shave. However, at this stage, staff expects that the facility modernization concept will not play a significant role in this rule amendment effort.

Response #3
Please refer to Appendix 5 of the 2007 AQMP for the evidence of how SOx emissions contribute to ambient particulate matter concentrations, and how the anticipated SOx emission reductions will affect ambient air quality.

Response #4
Staff 's seven-step approach for this rule amendment is described in Response #1. The first three steps were presented in Part I of the Preliminary Draft Staff Report and several staff's presentations at the SOx RECLAIM Working Group Meetings. To assist staff in the BARCT assessment, expert third-party contractor(s) conduct a thorough, independent, site-specific engineering evaluations and cost estimates of potential control technologies in Step 4. The results of the contractors' analysis will be used in Step 5 and Step 6. Staff will develop Part III of the Draft Staff Report Staff to cover the information in the last four steps in parallel with the contractors' work in Step 4.

Response #5
Staff will respond to all comments received and revise the Draft Staff Report appropriately. Regarding WSPA's detailed comments, staff will response to the key issues and retain the detailed comments in the Administrative Records of this amended rule. This approach was selected to reduce the bulk of the detailed comments/responses portion of the Draft Staff Report.

Responses to BP's Comments Received July 1st, 2008

BP West Coast Products, LLC
6 Centerpointe Drive

La Palma, Ca 90623

Telephone: +1 (714) 670-5493

VIA E-Mail
July 1st, 2008

CONFIDENTIAL BUSINESS INFORMATION

Ms. Minh Pham
Air Quality Specialist
Planning, Rule Development and Area Sources
South Coast Air Quality Management District
21865 E. Copley Drive
Diamond Bar, CA 91765

Subject: **2nd Round of Comments on RECLAIM SOx Shave Staff Report Part 1**

Dear Ms. Pham

BP appreciates the opportunity to comment on the draft Part 1 of the staff report for the RECLAIM SOx shave. I provided some initial comments on this report back on April 29th. Below are some additional company specific comments for these facilities that are not appropriate to share with WSPA. Please note that some of this information is to be treated as business confidential.

Refinery

Comment #1

- I suggest removing the sentences related to the CanSolv scrubbing system installed at the Cherry Point SRU mentioned in Section 5.3.3.2 of the report. It is true that the unit was started in July of 2006, but it only operated for about 4 months due to equipment problems outside of the CanSolv system. It is still not operating. It was also not designed to achieve 10 ppm as stated. In fact, the unit is designed to meet what the state regulatory agency determined to be **BACT** – 250 ppm SO2 12-hour rolling average (same as NSPS Subpart J/Ja) and it has a 135 tpy mass limit annually which I believe translates to 150 ppm. The following is an excerpt from the from the Marsulex Agreement for the design of the unit:
  SO_2 Removal. The concentration of SO_2 in the treated gas (stack gas) shall be less than 250 ppmv, oxygen fee, dry basis, (no nitrogen adjustment).

Calciner

Comment #2

- Similar to the request above, we respectfully ask that you eliminate the brief discussion about the BP Cherry Point Calciner control system in section 8.3.2 of the report. There are two reasons for this request. First, much of the basic information is inaccurate such as the permit chronology and statements suggesting that SO2 was reduced as a result of the installation of a wet ESP (specifically designed for particulate and acid mist removal, not SO2). Any apparent SO2 reduction was likely coincident with this change but due to something else. The likely cause of inaccuracies in the chronology is the result of having multiple calciners undergoing modifications at different times, but none of the dates mentioned line-up correctly with the specified modifications. To clarify all the permit history would require an expansive discussion without any real value added to the report. There is also 'test' data presented that the unit met 10-12 ppm SO2 in the stack. I did not see any such test data when I reviewed source test results.

  Secondly, the data from the Cherry Point calciner does not necessarily support the conclusion that the Wilmington calciner emission performance could be improved. While it is true that the stack concentration is consistently lower at Cherry Point, the removal efficiency is not any better. You list an inlet concentration range at Cherry Point of between 1125 and 1425 ppm. This information appears accurate based on some tests and translates into an inlet mass of 1200 – 1500 lbs/hr. However, as provided in our survey to SCAQMD, our analyzer data for 2007 shows inlet mass ranging at about 5200 lb/hr (2700 ppm) at Wilmington. I am not sure why the different levels of sulfur in the inlet exist, but this explains the slightly higher removal efficiency reported at Wilmington mentioned previously in my comments.

  None of this information suggests that wet scrubbing, as an option to the existing dry scrubbing system at Wilmington, should not be explored in the 3rd-party engineering analysis in Part II of the staff report or discussed generically in this section. I also do not have a concern if it is mentioned that such a system is installed and operating at the BP Cherry Point refinery. However, to avoid having to rewrite the complex permit history and trying to explain why Cherry Point has a consistently lower stack concentration while Wilmington has higher removal efficiency, I suggest removing the discussion of the Cherry Point performance in its entirety.

If you have any questions regarding these comments, do not hesitate to call me at (714) 670-5493 or reply to this e-mail.

Sincerely,
Miles Heller
Air Issues Specialist

Staff's Responses

Note that the commenter did not specifically identify or justify which information was confidential; therefore the comments will be treated as non-confidential.

Response #1

Staff does not agree with BP's suggestion to remove Section 5.3.3.2 of the Preliminary Draft Staff Report related to the Cansolv scrubbing system installed at Cherry Point Refinery's Sulfur Recovery Units.

Staff acknowledges the information provided by BP that 1) the Cansolv scrubber has been designed to a level *less than* 250 ppmv, 0% O2, currently required by NSPA Subpart J/Ja or MACT II, and 2) is subject to a mass annual limit of 135 tons per year, translated to 150 ppmv SOx, as BP. However, staff believes that it is not uncommon for a system to achieve levels below the designed levels. This fact is supported by the following examples:

- Two Cansolv scrubbers were designed for a FCCU and a FCU at Valero's Delaware City Refinery. The designed outlet SOx concentration is 25 ppmv. These scrubbers have been in operation for more than a year, and have actually achieved levels of 2 ppmv SOx outlet concentration on a continuous basis.

- Two DynaWave scrubbers were installed at Sinclair oil refineries in Wyoming and designed to meet less than 250 ppmv limit of MACT II and NSPS Subpart Ja. These scrubbers have been in operation more than a year and actually achieved a level below 1 ppmv (e.g., 0.3 ppmv which represents the lower detection limit of stack testing.)

Staff has provided accurate information in Section 5.3.3.2 related to the Cansolv system in the Preliminary Draft Staff Report, and as such, will not remove this section. However, staff will add a footnote to reflect the current non-operational status of the system as indicated by BP.

Response #2

Staff does not agree with BP's suggestion to eliminate Section 8.3.2 of the Preliminary Draft Staff Report related to the Cansolv scrubbing system at Cherry Point Refinery's coke calciners. Staff's responses to several issues stated in Comment #2 are as follows:

- **Permit Chronology**
  Following BP's suggestion, staff will not discuss the operational history and permit chronology of the calciners at BP Cherry Point Refinery. As such, staff removed the dates (e.g. 1984, 1994, 2001) mentioned in this section.

- **Accuracy of Emissions and Performance Information**
  Staff believes that it is important to state relevant public information related to the performance of the wet scrubbers/wet ESPs for the calciners at Cherry Point Refinery accurately. The information provided in the Preliminary Draft Staff Report was all correct and accurate, and will be repeated below with specific references provided:

Information	Reference
The inlet SOx concentration from the calciners at Cherry Point Refinery ranges from 1125 ppmv – 1425 ppmv	November 1, 1977 PSD Applicability Determination – ARCO Petroleum
Permit limit concentration of 160 ppmv and 90% control efficiency previously given to the wet scrubber	Northwest Clean Air Agency, Notice of Construction Worksheet for BP Cherry Point Refinery (NOC #985), dated December 2006
Permit limit concentration of 35 ppmv	Northwest Clean Air Agency, Air Operating Permit of BP Cherry Point Refinery
Control efficiency of the control system including wet scrubber and wet ESP	Estimated from inlet and permitted levels: (1 – (35 ppmv / 1125 ppmv))*100 = 96.9% (1 – (35 ppmv / 1425 ppmv))*100 = 97.5%
Test results showing 10 – 12 ppmv	From a paper titled "Eliminating a Sulfuric Acid Mist Plume from a Wet Scrubber on a Petroleum Coke Calciner", Brown & Hohne. This paper indicated an average annual SOx concentration of 18 ppmv and a SO2 removal efficiency of 99%.

Staff acknowledges that the main function of the wet ESP is to further control sulfuric acid mist emissions and eliminate visible plume. This fact was already mentioned in Section 8.3.2 of the Preliminary Draft Staff Report. However, the permit limit for SOx was reduced from 160 ppmv to 35 ppmv, and this fact speaks for itself about the concurrent effect on SOx removal efficiency.

- **Stack Concentration (ppmv), Removal Efficiency (%), and Emission Rate (lbs/ton)**
  The control efficiencies (98% - 99%) for Wilmington's coke calciners were based on actual outlet concentrations (27 – 52 ppmv) and inlet concentration (2700 ppmv). The control efficiencies (96.9% - 97.5%) for Cherry Point Refinery's coke calciners were based on ***permitted*** outlet concentration (35 ppmv) and inlet concentrations. When the actual outlet concentrations are used (10-12 ppmv), the control efficiency for Cherry Point Refinery's coke calciners will approach 99% or more.

  The emission rate of Cherry Point Refinery's coke calciner (0.14 lbs/ton) is lower than those at BP Wilmington (0.56 lbs/ton – 0.89 lbs/ton). The Tier I emission rate for BP Wilmington calciner was set high at 2.47 lbs/ton. In addition, the current reported production rate of Wilmington's coke calciner is approximately 22% higher than the past production rate reported by BP and used in Tier I allocation calculation. To balance the increase in production rate and to meet a potential lower BARCT level, staff strongly believes that BP should improve the performance of its control system at Wilmington's coke calciner.

Responses to Valero's Comments Received July 1st, 2008

-----Original Message-----
From: Gonzales, Susan [mailto:Susan.Gonzales@valero.com]
Sent: Tuesday, July 01, 2008 1:26 PM
To: Minh Pham
Subject: FW: Valero Del City
Importance: High

Hi Minh -listed below are the comments on the preliminary draft report. The comments are from our Valero Delaware City environmental department.

I've attached the document portion that I had them review. Thanks. Sue

Valero Delaware City Refinery Comments:

On page 1, in addition to Valero DE City, Motiva DE City is listed. The Motiva entry is a duplicate. We are the old Motiva DCR. The Valero DCR entry contains two footnotes (#2, #5). #5 footnoted below the table has an (a) and a (b). The (b) references a scrubber on an HF Alkylation Unit...and I don't know what this is referring to (some other Premcor refinery?) because we do not have an HF Alkylation Unit. I'm also not sure what the 65% reduction is referring to. The two regenerative WGS units on the FCCU and FCU here in DE City were designed to reduce emissions by 99% at the FCU and 97% from the FCCU.

Page 3 mentions inlet flow volume to the WGS. The design inlet volumes from the final permit applications are 258,200 scfm for the FCU and 442,400 scfm for the FCCU. These values are not on a moisture corrected (dry) basis. I also have no knowledge of the statement in the last sentence about the FCCU being "twice bigger than the largest refinery in the District."

Staff's Responses to Valero's Comments

Staff contacted Delaware Department of Natural Resources and Environmental Control (DNREC)'s Division of Air Waste Management to clarify about the name of the refinery and the status of operation. DNREC's staff confirmed that Valero had recently bought Delaware City Refinery from Motiva. DNREC's staff also indicated that there have been several ownership changes for this Delaware City Refinery; however this refinery is still referred to as "Premcor Refinery" on various documents such as permits.

Based on the information provided by Valero and DNREC, staff has:1) deleted the duplicate entry for Motiva in Table 3-3; 2) made a clarification in footnote #5 that Premcor Delaware City Refinery is now owned by Valero; 3) deleted several wordings in footnote #5 which referred to HF alkylation unit and 65% reduction (which was the estimated overall facility emission reduction from DNREC;) 4) included the two flow rates for FCCU and FCU in Paragraph 3.3.2.3 of the Staff Report; and 5) included additional information provided by DNREC that the two scrubbers have indeed achieved SOx levels of 1 ppm - 2 ppmv, corrected to 0% O2, on a continuous basis. The scrubber system for the FCCU is in operation for about 1.5 years, and the scrubber system for FCU is on line for more than 2 years. Based on a comparison on the exhaust flow rates from the FCCUs and feed rates, Delaware Refinery's FCCU is about twice larger than the largest FCCU in the District.

Responses to Rhodia's Comments Received April 29th, 2008

Rhodia Inc. provided comments and edits on Chapter 6 of the Preliminary Draft Staff Reports – Sulfuric Acid Manufacturing Process on April 20, 2008. Staff appreciates the comments and has incorporated many of Rhodia's edits in the newly revised version of the Draft Staff Report.

Responses to Rhodia's Comments Received November 25th, 2008

Comment #1

State law prohibits the District from setting BARCT levels without considering the relative environmental and economic impacts on each affected source category. The Draft Report fails to make any findings at all concerning (1) the relative cost-effectiveness of requiring the proposed SO2 controls at a sulfuric acid plant like Rhodia instead of requiring more reductions from sectors responsible for greater PM2.5 and/or SO2 contributions; (2) relative PM2.5 reductions available from tighter controls on sulfuric acid plants versus other sectors/sources; (3) relative costs and environmental benefits of imposing more aggressive controls directly on PM2.5 sources rather than on sources of SO2 (which is only a precursor to PM2.5); or (4) whether imposing stricter PM2.5 and/or SO2 controls on other sectors may cause less overall adverse economic impact than imposing those controls on Rhodia. For example, requiring additional reductions from highly emissive direct sources of PM2.5 very well could result in a greater and more cost-effective reduction of PM2.5 than driving down BARCT levels for sulfuric acid regenerators, who are a very small source of PM2.5 in the South Coast Air Basin. In any event, reciting control costs and cost-per-ton figures in a vacuum tells the District nothing about whether tighter regulation of other sources may be less economically burdensome and/or more effective at producing PM2.5 attainment by 2015. Accordingly, the Draft Report fails to provide a complete BARCT analysis.

Response #1

Staff recognizes that for a BARCT assessment to be made state law requires an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of sources. (H&S Code §40406) However, it should be noted that the results provided in the subject report is not the BARCT assessment but rather input for the staff to generate a recommended BARCT for the various equipment subject to SOx RECLAIM.

Comment #2

Since the District began its effort to investigate and redefine BARCT for SOx from sulfuric acid plants and other sources, both the credit markets and the broader economy have suffered major downturns. Financing for major projects is extremely difficult to secure, and most economic analysts predict that these credit issues will extend into 2009 and potentially 2010. The Draft Report makes no mention of these changed economic circumstances, and fails to discuss the potential impacts of tightening BARCT levels at a time when sources could find it difficult or impossible to complete the required capital projects by 2015.

Response #2
Addressing the current economic situation's impact on financing major projects is outside the scope of this report. Such dialogue has transpired as part of the SOx Working Group. Staff will try to schedule implementation of these projects with the lowest possible financial impacts while maintaining the 2015 emission reduction goals as presented in the 2007 AQMP.

Comment #3
AQMP Control Measure CMB-02 is a measure designed to secure appropriate SOx reductions pursuant to RECLAIM, primarily (as the AQMP describes) from refineries. It is not a control measure designed to achieve PM2.5 reductions required for District wide attainment. While the District certainly has an interest in achieving PM2.5 attainment in the South Coast Air Basin, Control Measure CMB-02 makes no mention of requiring SOx reductions as a PM2.5 reduction strategy. If the District's aim is to secure sufficient PM2.5 reductions to achieve PM2.5 attainment by 2014, it must fairly compare the costs and benefits of securing PM2.5 reductions from the universe of PM2.5 sources throughout the Basin, not disproportionately from a handful of SOx RECLAIM sources.

Response #3
The staff report will address the relationship between SOx and PM2.5. However, the commenter is referred to such documents as Appendix V of the 2007 AQMP for a much more detailed discussion of this relationship.

Comment #4
The capital cost estimates in the Draft Report (summarized in Table 3 on page 8 and in Table R-2 in Section V.L. of the confidential appendices) appear to be inaccurate, and vary from each other by over $6 million. Rhodia has been unable to verify the sources of these equipment cost estimates, both of which are well below the likely installed equipment costs of installing a caustic scrubber. Recent experience within our company and throughout the market suggests to us that the installed cost of a scrubber is approximately $15 million. For these reasons, the cost effectiveness values in Table 4 on page 9 are also too low, and do not reflect real world costs. Moreover, in Section V.M., Table R-3., the operating cost estimates for caustic makeup also appear to be too low, given that current market value for caustic is approximately $1,000 per ton (100% NaOH). These data errors undermine the Draft Report's cost effectiveness conclusions on page 10, and suggest that actual capital and operational costs may be significantly higher than the numbers cited. Because California law mandates that the District make proper cost-effectiveness findings before setting or changing BARCT, Rhodia strongly recommends that the District take the PDSR off the December calendar, ask its vendors to document the sources for all of the cited cost data, and work with Rhodia to resolve the data discrepancies before moving forward.

Response #4
The consultant has conducted a very thorough analysis with respect to the cost analysis of the subject equipment. However, given the very low cost effectiveness derived by the consultant the

costs would have to be several-fold greater than assessed in order for the cost-effectiveness to no longer being attractive.

Comment #5

The Draft Report assumes that Rhodia could install a new caustic scrubber as soon as 2011. Rhodia estimates that, if it were required to install a new scrubber, it would not be ready for operation for at least 2 to 3 years after initial funding of the project. Even in a best-case scenario, emissions reductions from any new scrubber installed at Rhodia may not be available to help PM2.5 attainment until 2012 or later, depending on when the District approves the BARCT revision. The Draft Report fails to address the relative costs and benefits of requiring SO2 emissions reductions that would not yield PM2.5 reductions until those years, nor does it address whether reductions in other sectors may be more timely and cost-effective.

Response #5

The SOx emission reduction goal of at least 2.9 tons per day needs to be made prior to 2015. Staff will assess the feasibility of achieving this emission reduction in the indicated timeframe as part of the rulemaking process, taking into consideration the time needed to install control equipment.

Comment #6

In the first paragraph of page 4 of the Draft Report, we would recommend adding the following underlined language: "Historically double absorption plants have needed no further SO2 reduction before the tail gas is emitted to the atmosphere, because their emissions are typically well below the New Source Performance Standard of 99.7% conversion or 4 lbs. per ton." In the second paragraph on page 4, we would recommend deleting the word "pentoxide" from the catalyst description. Extensive research conducted by Rhodia's catalyst supplier indicates that the vanadium is in a form of complex salts rather than vanadium pentoxide.

Response #6

The consultant opted not to include the language in the subject report. If appropriate staff may include such language in the staff report.

Comment #7

In Figure 1 on page 6, "Facility 1, 2, 3", should be changed to "Facility A, B, C," respectively, to be consistent with the rest of the Draft Report. In the confidential section of the Draft Report

Response #7

The consultant corrected the facility identification as indicated by the commenter.

Comment #8

Finally, though Rhodia provided extensive comments and edits to the last draft of the PDSR, none of those comments appear to have been incorporated into the version that was posted on the District's website. Rhodia also provided comments to an earlier version of the PDSR, but only a fraction of those comments appears to have been incorporated into the current version. Indeed, the District has failed to provide any response at all to most of Rhodia's comments on the PDSR. Rhodia is concerned that the District may be on a path to adopting a new and stricter *set of BARCT requirements without sufficiently considering or incorporating Rhodia's written comments.*

Response #8
Staff will respond to such comments as part of the staff report development.

Responses to WSPA's Comments Received April 29th, 2008

Comment #1
Part I, as drafted, contains numerous examples of the topics that are apparently intended to be covered in Part II. In addition to being premature, the discussion of these items in Part I is largely unsubstantiated and lacking adequate detail. WSPA strongly suggests that contents of the Part I Staff Report should conform to the scope specified in the above paragraph.

The methodology by which the District will actually develop the recommended RECLAIM SOx allocations shave is a critical discussion that should be included up-front, in the Part I Staff Report. (There is currently no mention of this essential topic.)

WSPA notes that the revised draft RFP for the third-party contractor project mentions that the Part II Staff Report will include "... a discussion on the process for reassessing BARCT, appropriate BARCT levels, emission reductions (aka allocations shave) and cost effectiveness for RECLAIM program (sic)." However, we submit that an understanding of, and agreement with, the methodology for developing a recommendation for an allocations shave – along with the necessary compliance margin – needs to proceed most of the other work (e.g., the third-party contractor project). In fact, arguably, we have already gotten "ahead of ourselves".

The methodology for the NOx shave proved to be very complex. Because we would expect a similar level of complexity with regard to SOx, the discussions regarding process cannot wait for a Phase II Staff Report. We should not delay those discussions any further – they need to commence now.

Response #1
Staff appreciates the concerns raised by WSPA in having an understanding of the SOx shave methodology. In recent meetings with the refineries and as requested by the refinery task force, staff has agreed to provide an estimate of SOx RTC reductions following the methodology that was used in the January 2005 NOx RECLAIM amendment. However, as in the January 2005 NOx RECLAIM amendment, further discussions are warranted (e.g. BARCT assessment) prior to finalizing the RTC reductions.

Comment #2
The decrease in the number of RECLAIM SOx facilities warrants some discussion and analysis. In particular, there would be interest in knowing whether or not any facilities have ceased operations, and, if so, why they did.

Response #2

Please refer to the Annual RECLAIM Audit Reports presented to the AQMD Governing Board on an annual basis in March. The most recent reports were presented to the Governing Board for the 2007 compliance year. These reports provide information pertaining to the number of RECLAIM facilities. Such a discussion would be outside of this proposed SOx RECLAIM amendment.

Comment #3

WSPA understands that BARCT reassessments for the District's RECLAIM program are required by the California Health and Safety Code rather than by the Federal Clean Air Act. The discussion should clarify that advancements in control technology may or may not have actually occurred. Further, it is the RECLAIM program itself that dictates the timing for the planned reductions in emissions – a BARCT reassessment does not, by itself, impact implementation timing.

Response #3

A BARCT reassessment and the timing for this process (e.g. as expeditiously as practicable) is required by both the federal and California Clean Air Act, namely Section 172(c)(1) of the federal CAA, and Health and Safety Code (H&SC) Section 40913, 40914 and 40920.5, 40440(b)(1), 40406, and 39616. Staff conducts a BARCT reassessment every three years which realign well with the frequency for amending the Air Quality Management Plan.

Comment #4

The relationship of the Federal Fine Particulate Implementation Rule is this current effort to reassess BARCT for source categories that emit SOx needs to be clearly explained. The District's Rule and Control Measure Forecast item that describes this RECLAIM effort refers only to AQMP Control Measure CMB-02, and CMB-02 is a measure to achieve a proposed 2.9 ton per day reduction of SOx emissions.

Response #4

SOx is a key precursor of particulate matter (PM2.5). Reducing SOx is very important since it would help the Basin to meet the annual PM2.5 standard in 2014, the 24-hour PM2.5 standard in 2010, and ready to face a potential revision of the PM2.5 standard in a near future. Other than mentioning the importance at reducing SOx because it is a key precursor to PM2.5, there is no real need to provide detailed information regarding this phenomenon. The commenter is referred to such documents as the Appendix V of the 2007 AQMP for more details on this subject.

Comment #5

The value of the target SOx reduction in the final version of CMB-02 is "2.9 tons per day" (and that was a change from the initial estimate of "3.0"). The regulated community needs to know, and fully understand, the District's goals with respect to MCS-01, and the process for potentially combining "facility modernization" with this current effort to reassess BARCT for RECLAIM sources. These issues need to be included in the Part I Staff Report.

Response #5

As stated in Control Measure CMB-02, the minimum target emission reductions are expected to be 2.9 tons per day (~ 3 tpd) from 2010 through 2014 and are expected to remain constant after 2014. Such reduction in allocations can be across-the-board shaved or source specific reductions. As stated in CM CMB-02, staff may need to explore the feasibility to incorporate the concepts of Control Measure MCS-01 - Facility Modernization, to achieve reductions beyond 2014. If needed, staff will discuss the concepts in Part II of the Staff Report.

Comment #6

It would be appropriate to include discussion and analysis of the following topics:

- *The appropriateness of using CY 2005 as a "baseline" year.*
- *The methodology for calculating CY 2005 emissions since RECLAIM facilities are found in both calendar year and fiscal year cycles (i.e., there are both Cycle 1 and Cycle 2 facilities).*
- *The 2 ton per day differential between RECLAIM SOx allocations and actual SOx emissions. (For example, how much was allocated to operating facilities compared to third-parties who do not operate facilities. This information goes to establishing an appropriate compliance margin, and determining how deep a hypothetical shave would cut into facility operations.*

Response #6

Staff provides the following explanations:

- The development process for the amended SOx RECLAIM rules started in late 2007. At that time, the most recent set of emission data that has been available and audited is the 2005 emission data, therefore staff used this set of data in the analysis of the Staff Report. For further information, please refer to the "Annual RECLAIM Audit Reports for 2005 Compliance Year" published in March 2, 2007.

- Staff did not "calculate" any emissions for RECLAIM facilities. Cycle 1 and Cycle 2 facilities are required to report emissions according to the same reporting protocol in Rule 2012 for SOx (e.g. major SOx sources must report emissions on a daily basis and process SOx sources must report emissions on a quarterly basis.) Following are the reporting emissions group by compliance year (e.g. Emissions for compliance year 2002 means emissions reported from January 1, 2002 – December 31, 2002 for Cycle 1 facilities, and July 1, 2002 – June 31, 2003 for Cycle 2 facilities. Emissions for calendar year 2002 means emissions reported from January 1, 2002 – December 31, 2002 for both Cycle 1 and Cycle 2 facilities.)

- The 12 tons per day corresponds to allocations and also emissions reported in APEP for compliance year 2002 (from Jan – Dec 2002 for Cycle 1 facilities and from July 2002 – June 2003 for Cycle 2 facilities). The 10 tons per day emissions are the emissions reported for 2005 calendar year. The difference in 2 tpd between year 2002 & 2005 is mainly the result of shrinkage in SOx universe from 41 facilities since the start of the RECLAIM program to 33 facilities in 2005 including 12 facility shutdowns, 8 inclusions and 4 exclusions is only about 10%.

Comment #7

The calculations above do not appear to be correct. Because the seven highest emitting source categories had CY 2005 emissions of 7.53 tons per day out of a total of 10 tons per day, their contribution is 75 percent (10 tons per day x 95 percent x 90 percent = 8.6 tons per day [or, 86 percent] – but that does not agree with 7.53/10).

Response #7
The following values need to be part of the calculation in order to derive the correct product:
9.92 tpd x 93.95% x 80.79% = 7.53 tpd (for the top 11 facilities)
9.92 tpd x 95.46% x 81.09% = 7.68 tpd (for the top 12 facilities, where Saint Gobain Containers Inc has ceased operation).

Comment #8
WSPA believes that SOx allocations, which are held by entities other than RECLAM facilities, need to be noted and that Table EX-1 should show possibly those allocations if they are significant.

Response #8
Staff added Table ~~A-3~~A-2 in Appendix A to provide information (RECLAIM Trading Credits) that is held by entities other than RECLAIM facilities.

Comment #9
Notwithstanding staff's efforts in this regard, WSPA believes that the discussion of potentially applicable control technologies must be a work product of the third-party contractor study that the District has proposed. The discussion and analysis of control technologies should be included in the Part II Staff Report – not in this Part I.

It is both premature and inappropriate to present this list of candidate potential control technologies as being proposed technologies. The candidate control technologies will need to be evaluated against the BARCT criteria, and that analysis needs to take place in Part II of the staff report. More appropriately, the analysis needs to occur within the scope of the potential third-party engineering contractor project, on which, WSPA would expect, Part II of the staff report will be based.

Response #9
There is nothing premature and inappropriate in presenting information in Table EX-2 based on staff's research presented in Part I of the Staff Report. Staff views most rulemaking efforts as an iterative process. Staff expects that the independent work of the third party contractors will not result in much of a difference to the information presented in Table EX-2. However, if there is a difference, staff will consider the difference in the BARCT assessment process for SOx RECLAIM.

Comment #10

It is highly speculative to propose combinations of control technologies for these various sources because, in many cases, the technologies are essentially mutually-exclusive[73]. *There would need to be a robust demonstration of the feasibility, the effectiveness, and the cost-effectiveness of potentially combining multiple control technologies for these source categories.*

Response #10
Under certain situations, control technologies are mutually-exclusive. It is, however, not highly speculative that control technologies would be used in combination. For example, it is quite possible for a facility to combine wet scrubbers with SOx reducing additives. Table EX-2 provides possible control technologies, not the proposed BARCT. In addition to the information provided in Part I, the BARCT analysis will be made with the results provided by the third-party contractors as well as additional input from the regulated community.

Comment #11
As noted previously, the actual target emission reduction in CMB-02 is 2.9 tons per day (not 3 tons per day). The claim that the listed control technologies "would be employed to generate at least 3 tpd" suggests that the staff has already reached important conclusions regarding the potential BARCT reassessments and the amount of the potential reduction of SOx allocations, respectively. Given the facts that the proposed third-party engineering study has not yet begun, and that Part II of the Staff Report has not been written, all such conclusions are premature and inappropriate for inclusion in the Part I Staff Report.

Response #11
Staff conducted a first estimate of emission reductions of 2.9 tons per day shown in Control Measure BCM-02. A more refined estimate of emission reductions (4.7 tpd – 6.7 tpd from the 2005 baseline inventory) was conducted during the development of Part I of Staff Report and was provided in the April 3 and April 30 Working Group Meetings. A subsequent estimate of emission reductions (6.5 tpd from the 2005 baseline inventory) were provided by the third-party contractors.

Comment #12
WSPA submits that the definition of BARCT is critical to this current effort. BARCT is not BACT or LAER. BARCT applies on a retrofit basis and it must consider environmental, energy and economic impacts.

Response #12
Staff agrees with the commenter. However, it should be noted that it is not unusual in which the levels of BARCT are equal to the levels for BACT (or LAER), especially for add-on control devices such as wet/dry scrubbers. In some situations (e.g. PAR 1146 and 1146.1), the BARCT level for certain categories of equipment may be more stringent than the corresponding BACT level. The primary reason for this difference was that the BACT assessment has not been

[73] For example, it is extremely unlikely that, due to "diminishing returns", anyone would: Combine wet scrubbing of FCCU flue gas with any other SOx-reduction technology, or, combine enhanced fuel gas treating for fuel gas combustion devices with stack scrubbing, or, combine enhanced SRU/TGU efficiency with stack scrubbing, etc.

conducted for 8 years, not taking into recent advancements on control technologies. In addition, BARCT may anticipate future technological development.

Comment #13A
Although WSPA recognizes the precursor relationship between SOx emissions and ambient PM 2.5, as a practical matter, the discussion in the following section is confusing – largely because it fails to establish a clear and understandable relationship between PM and this effort regarding the RECLAIM SOx program.

Comment #13B
First, the two statements in the preceding paragraph, taken together, are not clear. Second, the statistic regarding the exposure of Southern California residents to PM 2.5 needs to be substantiated. For example, there needs to be some discussion regarding the nation-wide monitoring for PM 2.5, etc. (if PM monitoring data for the rest of the nation is sparse, then PM monitoring in a densely populated area such as Southern California would skew the result).

Comment #13C
Without establishing the basis, the discussion in the paragraph above is seemingly unrelated to SOx RECLAIM.

Response #13A-13C
Please refer to the 2007 AQMP and specifically Appendix 5, for further explanations.

Comment #14
WSPA is concerned that the discussion in the paragraph above implies that the District intends to use RACM and RACT as two barometers for evaluating potential SOx reduction technologies rather than using BARCT, as discussed earlier in the staff report.

As stated previously, the preliminary draft Part I report has not established a basis for linking SOx reductions to improvements in PM air quality. The discussion regarding the effectiveness of controlling SOx and/or NOx for PM air quality improvement needs to be substantiated.

Response #14
RACM and RACT call out for a minimum level of control required by the U.S. EPA in their Clean Air Fine Particle Implementation Rule. The District is required to establish BARCT for this proposed SOx RECLAIM rule amendment as discussed earlier in the Staff Report. BARCT would more likely be more stringent than the levels presented in RACM/RACT.

This Staff Report incorporates other documents which establish a basis for linking SOx reductions to improvements in PM air quality as part of the rule making documents. This linkage is well documented and substantiated in other public documents such as the 2007 AQMP, and documents that were used as the basis to develop the Clean Air Fine Particle Implementation Rule.

Comment #15

WSPA suggests that the staff report should list the SOx facilities that have exited RECLAIM, and should indicate the reason for their leaving the program (and, if due to plant closure, did the business claim that the decision to close was in any way related environmental regulations, or, the RECLAIM program in particular).

Response #15

Please refer to the District's annual RECLAIM audit reports published annually in March for this information. Typically plant closure is the result of several factors. Staff believes that discussions on plant closures, or facilities opt-in into SOx RECLAIM is better placed in the RECLAIM annual audit reports.

Comment #16

The first two sentences are unclear (e.g., were the decreasing allocations based on BARCT that was initially in place or, that would likely be implemented in the future?).

The statement assumes that advancements in control technology are occurring constantly but, as a practical matter, that is not the case. The sentence should read, "capture any advancement ...".

The concept of declining emissions allocations, which were a basic design element of the RECLAIM program, already incorporate the goal of expeditious emissions reductions. The sentence could report a more accurate number – the actual reduction was 22.5 percent.

Response #16

The decreasing allocations were based on, in part, the levels of BARCT that would be implemented as expeditiously as possible in the future.

Staff did not intend to imply the control technologies are "constantly" being improved. Rather staff is alerted at technology advancements, or retrospectively leads back to ascertain if control technology improvements warranted a BARTC assessment. Either approaches recognized progress made by the regulated industry, vendors and contractors in control technology advancements.

The concept of declining emission allocations indeed incorporates expeditious emission reductions. The facility allocations since 2003 remain constant based on a BARCT assessment in 1993. A BARCT re-assessment today will in all likelihood establish further declines in SOx emission allocations in order to reach PM2.5 attainment in 2015.

Since its initial rule making effort, there have been several amendments to the RECLAIM rules. In January 2005, a BARCT analysis was re-conducted for NOx, and as a result of this analysis, the RECLAIM rules were amended and the NOx annual allocations previously given to the NOx RECLAIM facility were further reduced by approximately 20% to reflect BARCT.

Comment #17
WSPA recalls that the 2003 allocations included an extra "shave". Tier 1 represented BARCT at the time; Tier 2 was an additional 34 percent shave

The BARCT analysis for SOx is being re-evaluated through the current staff effort. It would be more correct to state that an amendment is (or, will be) based on the BARCT reassessment.

Response #17
A BARCT assessment in 1993 established the declining Tier 1 and Tier 2 allocations. BARCT is undergoing a reevaluation in this Staff Report and will in all likelihood set another reduction for SOx allocations.

Comment #18
WSPA strongly believes that, as was the case for the RECLAIM NOx program shave, any SOx shave must apply to the universe of RECLAIM SOx facilities.

Although the estimated SOx reductions in the AQMP control measure are accurately stated, the AQMP control measure did not contain any documentation regarding the basis for the numbers. Because it is not possible to verify, or even comment on, the reasonableness of the estimates, they must not become benchmarks for evaluating the potential outcome of the BARCT reassessment and SOx-shave.

As previously stated, there needs to be an explanation of the process for evaluating the possible secondary goal of including MCS-01 with this BARCT reassessment. WSPA is concerned that potentially combining two the goals will make it difficult to conduct their respective analyses.

Response #18
The paragraph written in Section 1.4 correctly stated the information presented in the Control Measure CMB-02.

Staff first conducted an analysis for emission reductions in 2006 during the development of Control Measure CMB-02 which resulted in a minimum of 2.9 tpd (approximately 3 tpd) emission reductions. Staff conducted a follow-up analysis in April 2008, resulting in a range of emission reductions from 4.7 tpd – 6.7 tpd from the 2005 emissions baseline. This range was presented in the April 3 and April 30 Working Group Meetings. Expert contractors conduct a third independent analysis of emission reductions and cost effectiveness in September 2008 to assist staff in making its final determination of BARCT. They estimated about 6.5 tpd emission reductions from the 2005 emissions baseline. The final results of potential RTC reductions and how the reduction would be distributed to maintain the integrity, equity and characteristics of the RECLAIM program will be discussed in Part III of the Staff Report. If needed to achieve addition emission reductions for 2014, staff will incorporate the concepts of Control Measure MCS-01 as stated in CM CMB-02, and will discuss the process in Part III of the Staff Report.

Comment #19
In view of the potential review of BARCT to be conducted by an engineering contractor, the staff's recent effort can only be regarded as preliminary. Further there is an important

distinction between identifying technologies that might be applicable to a particular source category, and making an assessment that any technology or combination of technologies represents BARCT.

Response #19
Staff has conducted an extensive engineering research to identify the control technologies and assess the possible potential emission reductions that can be achieved. The third party contractors will conduct their own engineering assessment on control technologies, and cost estimates to assist staff in making the final decision on BARCT and emission reductions.

Comment #20
It is premature to state that the SOx reductions technologies, which are described in the staff report, are "applicable" – those determinations have not yet been made, and can only be made at the conclusion of the proposed engineering contractor study.

Reports of installed costs and resultant cost-effectiveness, as reported in the "literature", are usually for uncontrolled sources. The reports are rarely applicable to sources that are already well-controlled, as is the case for facilities in the South Coast Basin.

Generally speaking, reliance on cost or cost-effectiveness values from "the literature" would be a serious mistake. In many cases the District has access to information regarding the actual costs of installations at local refineries. In other cases, site-specific engineering estimates need to be made because this entire BARCT reassessment exercise has to focus on potential retrofit installations.

Response #20
As pointed out in previous responses, the technical feasibility and cost analysis is developed over the entire rule making process. Relying upon data from literature is acceptable in the earlier stage of the rule development process.

Comment #21
WSPA notes that, in the absence of specific documentation regarding the reason that a facility installs emissions control equipment, it cannot be assumed that such installations have been determined to be cost effective. Many installations of emission control equipment have nothing whatsoever to do with cost-effectiveness considerations – rather, they might be part of negotiated Consent Decrees, they might be based on need to provide emissions offsets, etc. Where any determinations regarding cost-effectiveness might have been made, and when those determinations are quoted in the Staff Report, they need to be documented.

It is premature to suggest any definitive conclusions with respect to the amount of SOx emission reductions that might be expected. If various control technologies are ultimately determined to be feasible and cost effective, then the resulting reductions will be used in calculating the specific amount of the allocation shave for SOx RECLAIM sources.

Response #21

In CM CMB-02, staff estimated a range cost effectiveness from $10,000 - $16,000 per ton SOx reduced. The third party contractors will assist staff in conducting detailed cost estimates for this rule amendment and the results will be presented in Part II of the Staff Report.

Comment #22

The discussion in the preceding paragraph should reflect the proposed engineering contractor study.

Response #22

Staff will revise the Preliminary Draft Staff report accordingly when new information surfaces. The third party contractors' analyses will be summarized and presented in Part II of the Staff Report.

Comment #23

WSPA believes that the 12 ton per day value represents SOx allocations, not actual emissions. We also note that not all of the allocations are held by RECLAIM facilities (some allocations are held by third-party investors, etc.). WSPA cautions that care needs to be taken to distinguish between SOx allocations and actual emissions.

It is also important to show the SOx allocations held by facilities compared to those held by investors for both current and future years because the amount of allocations held by investors will increase proportionally in 2012 (compared to 2008) while the amount held by facilities will decrease.

Response #23

As shown in Table 3-4 of the "Annual RECLAIM Audit Report for the 2002 Compliance Year", dated March 5, 2004, the actual emissions for compliance year 2002 was 4,374 tons (12 tpd). The total RTCs (allocations and converted ERCs) were reported to be 4,924 tons (13 tpd).

The RTCs held by investors and by facilities may change on a daily basis. As of March 11, 2009, the RTCs held by the investors were 295 tons for compliance year 2009, 207.5 tons for compliance year 2010 (a decrease compared to year 2009), and 339.9 tons for 2011 and beyond.

Comment #24

Because Table 2-1 makes a comparison between the RECLAIM NOx and SOx programs, respectively, it is important to note the following:

- *The NOx shave applied equally to all facilities in the RECLAIM NOx universe.*
- *The NOx shave recognized the need for, and included, a compliance margin.*

These two characteristics of the NOx shave must also apply to the present consideration of a SOx shave.

Although the data show that, with respect to SOx, RECLAIM facilities represent a greater portion of the emissions inventory, they do not by themselves support a claim of any unusual importance for the current BARCT reassessment exercise for SOx. As stated above, WSPA believes that the 12 ton per day number represents allocations not emissions.

Response #24

In the NOx universe, 87% of the total emissions (24.02 tpd out of 27.61 tpd for compliance year 2003) are generated from the top 16% (54 out of 346 facilities) of the facilities. Yet the NOx shave is divided equally (by percentage) across the NOx universe. Therefore, similarly in the SOx universe, even though 95% of the total emissions (9.47 tpd out of 9.92 tpd) is generated from the top 12 facilities out of 33, the SOx RTC reductions will probably be divided equally (by percentage) across the SOx universe. As indicated in Control Measure CMB-02, however, the shave may be divided equally to 33 facilities, or may be restricted to specific facilities. As indicated in Part III of the Draft Staff Report, additional analyses will be conducted to provide more information on how the RTC reductions should be executed to maintain the integrity and operational of the SOx RECLAIM program.

See Response #3 regarding the requirement of BARCT reassessment. The 12 tpd is actual emissions in compliance year 2002.

Comment #25

Projected emissions for future years 2014 and 2023 are speculative at best. The staff report should indicate whether or not future year emission projections include the effect of allocation shaves. The precursor relationship of SOx to ambient PM should not simply be described as a "given" because there is no foundation for this claim in the staff report.

Response #25

The future estimated emissions for 2014 and 2023 (11.7 tpd and 11.8 tpd, respectively, without allocation shaves; and 8.8 tpd and 8.9 tpd, respectively, with allocation shaves) are clearly shown in CM CMB-02. The foundation and explanation for a relationship between SOx emissions and ambient PM can be found in Appendix 5 of the 2007 AQMP.

Comment #26

WSPA is not aware of any refineries in the South Coast basin that are not in the RECLAIM program. The staff report should clarify this issue.

Response #26

For clarification, the wording "Non-RECLAIM Refineries" are changed to "Non-RECLAIM Sources". In 2002, the refineries reported 6.9 tpd SOx emissions for flares and upset conditions. Flares and upset conditions were not counted in "RECLAIM Sources", which was ranked #2 in Table 2-2.

Comment #27

The language in the staff report consistently (and, perhaps, misleadingly) suggests that a 3 ton per day (the correct value is 2.9 tons per day) reduction in SOx allocations is a virtual certainty. It is not – primarily because the origin of the 2.9 ton per day goal has not been substantiated. The purpose of the BARCT reassessment is to determine the level of the SOx allocations reduction, if any, that is appropriate and can justified on the basis of available retrofit technology, cost effectiveness, etc. Further, it should be noted that other source categories in Table 2-2 might be reasonable candidates for SOx emissions reductions.

Response #27

As shown in the 2007 AQMP (Table 3-8 of Chapter 3 of the 2007 AQMP), RECLAIM sources were ranked #2 in SOx emissions in 2002, and were expected to rank #2 in 2014 and 2023. Among other stationary sources, RECLAIM sources have the highest possibility to achieve 3 tons per day reductions in 2014 cost effectively, substantiated by staff's analysis in CM CMB-02 and the analysis in Part I of Staff Report. The cost effectiveness ranking of all stationary source control measures in the 2007 AQMP is shown in Table 6-5.

Comment #28

As noted previously, the staff report should address the significance of using CY 2005 as a reference:

- What is the significance of CY 2005?
- Is CY 2005 a representative year? (Some analysis and discussion is needed.)

There needs to be some discussion regarding why the analysis was cut off at twelve facilities. There needs to be some discussion of the reason for, and implication of, including a facility that is shut down in this analysis.

Response #28

Please refer to Response #6.

Comment #29

The derivation of the claimed 80 percent value needs to be presented. (See the comments regarding Table EX-1.)

Response #29

Please refer to Response #7.

Comment #30

There needs to be some demonstration regarding the selection of 2005 as the baseline year.

Response #30

As presented in the April 3 Working Group Meeting (slide #4), the 2005 emissions were selected to be used in this rule amendment because they are within the range of emissions from other current years. The emissions from these top emitting categories of equipment were reported to be 7.5 tpd for 2005, 7.9 tpd for 2006, and 7.3 tpd for 2007. Staff also will estimate RTC reductions using other baseline year (1997) as shown in the 2005 NOx RECLAIM amendment.

Comment #31

There should be some discussion regarding the characterization of a source as "major", and it should be noted that this description has a specific meaning within the context of Regulation XX.

Response #31

The definition for major SOx source is in Rule 2011 (c).

Comment #32

It should be noted that many of the FCCUs at refineries in the South Coast basin are also equipped with expander turbines, which are used to recovery energy from the flue gas leaving *the regenerator. An expander turbine, and its associated third-stage separator (used to reduce filterable PM in the FCCU flue gas stream entering the turbine) are additional elements in the flue gas train, which collectively complicate the task of maintaining the required pressure balance within the FCCU.*

Response #32
Staff acknowledges this component of the FCCU operation. However, Figure 3-1 is a generic flow diagram that was never intended to show every single piece of equipment included in the FCCU at each refinery. Any components which would complicate the reductions of SOx emissions should be captured in the third party consultants' analysis.

Comment #33
An electrostatic precipitator and an SCR unit (where one is employed) occupy considerable refinery plot space, and limit the potential use of other systems such as wet gas scrubbers.
The title of the Figure should be "Typical Fluid Catalytic Cracking Unit". A block representing expander turbines should be added because these are common. The block representing SCR should be deleted or labeled as "Optional", because SCRs are uncommon.

Response #33
See Responses #32.

Comment #34
RECLAIM allocations were not issued to process units or individual pieces of equipment but, rather, to the facility as a whole.

Response #34
RECLAIM allocations were issued to the facility as a whole. However, total facility allocations were estimated for each SOx source at the facility according to the methodology described in Rule 2002.

Comment #35
The average value for the three years, 2005, 2006 and 2007 is 3.33 tons per day. There should be an explanation regarding why the highest year was used. Further, there needs to be an analysis regarding the impact of FCCU turnarounds, if any, on the mass emission estimates. (Also see comment for Table 3-2 below.)

Response #35
Staff started the development of this SOx RECLAIM amendment in November of 2007. The most recent set of RECLAIM emissions audited at that time was the 2005 emissions (Ref: *Annual RECLAIM Audit Report for 2005 Compliance Year*, March 2, 2007). Staff will provide two sets of estimation: 1) "real" emission reductions expected from the 2005 actual emissions baseline; and 2) RTC reductions based on the 1997 and the 2005 actual emission baselines. (The RTC reductions estimated from the 1997 baseline will be conducted as suggested by the refinery task force in several meetings with the District following the methodology outlined in the analysis for the 2005 NOx RECLAIM amendment.)
Comment #36

The statement regarding the lack of specific SOx concentration or mass limits for FCCUs is not correct. FCCUs can be subject to Federal New Source Performance Standards, provisions of Consent Decrees, etc.

As noted above, RECLAIM SOx allocations are provided to the facility not to a process unit (e.g., an FCCU). The amount of a facility's SOx allocations have been steadily declining since they were first granted at the start of the RECLAIM program.

Commercial availability is only one issue that needs to be considered when evaluating BARCT – other considerations are environmental, energy and economic impacts.

WSPA is not aware of any basis for the statement implying a hypothetical increase in capacity, and a corresponding need to upgrade any control device. The statement is unsubstantiated and should be deleted.

Response #36

The statement regarding the lack of specific SOx concentration or mass limits for FCCUs was meant for AQMD RECLAIM regulations, not EPA regulations.

The facility's SOx allocations are the summation of all allocations estimated for each SOx source/process category at the refinery. The facility's SOx allocations were steadily declining since 1993 to 2003, and remaining constant after 2003.

In the analysis of BARCT, staff will include only commercial availability technologies but not the technologies in development or at the research phase, and will evaluate BARCT considering environmental, energy and economic impacts as governed by federal/state rules.

The commenter may not be aware of any increase in FCCU capacity since it is confidential information.

Comment #37

WSPA submits that it is unlikely that each refinery had the same FCCU SOx emissions factor. That does not seem reasonable. We wonder if 13.7 lbs/1000 bbls might have been the Tier 1 shave target, not what was actually being emitted in the so-called peak years?

Response #37

The 13.7 lbs/1000 bbls is the emission factor used to calculate Tier I emissions for FCCUs.

References

AQMD, 2007. *South Coast Air Quality Management District – 2007 Air Quality Management Plan*, June 2007.

AQMD, 2006. *RECLAIM 2005 Annual Permit Emissions Report*, March 2006.

AQMD, 2007. *Facility Permit to Operate of BP West Coast Products LLC, BP Wilmington, Draft, Facility ID 131249*. September 25, 2007.

AQMD, 2007. *Addendum to the August 2006 Final Environmental Impact Report for the Chevron Heavy Crude Project*, certified May 2, 2007.

AQMD, 2003. *Rule 1105.1 and Staff Report – Reduction of PM10 and NH3 from Fluid Catalytic Cracking Units*, November 3, 2003.

BP, 2001. *BP Exploration & Oil Company, Amoco Oil Company, and Atlantic Richfield Company - Consent Decree*, Civil Case No. 2:96CV095RL, 2001.

BP, 2005. *BP Texas City Site – Texas City, Texas – 2004 Environmental Statement*, June 2005.

BP, 2007. BP Coke, 2007, http://coke.bp.com/tech/tech.cfm.

BUTLER, 2006. *Reducing Refinery SOx Emissions*. E. Butler, K. Groves, J. Hymanyk of Chevron Canada Limited and M. Maholland, P. Clark, and G. Aru of Intercat Inc. Petroleum Technical Quarterly, Quarter 3, 2006.

CARB, 1978. *Feasibility of Installing Sulfur Dioxide Scrubbers on Stationary Sources in the South Coast Air Basin of California*. Prepared by P.P. Leo and J. Rossoff of The Aerospace Corporation for California Air Resources Board, Contract No. A6-211-30, August 1978. http://www.arb.ca.gov/research/abstract/a6-211-30.htm

DWR, 2010. The 2009 California Water Plan Update.

EAGLESON, 2005. *A Logical and Cost Effective Approach for Reducing Refinery FCCU Emissions.* S.T. Eagleson, G. Billemeyer, N. Confuorto, and E. H. Weaver of BELCO Technologies Corporation, and S. Singhania and N. Singhania of Singhania Technical Services Pvt., India, Presented at PETROTECH 6th International Petroleum Conference in India, January 2005

ENVIRONMENTAL PROGRESS, 2001. *Eliminating a Sulfuric Acid Mist Plume from a Wet Caustic Scrubber on a Petroleum Coke Calciner*, Charles Brown and Paul Hohne of VECO Pacific Inc., Environmental Progress, Vol. 20, No. 3, October 2001.

EPA, 1983. *Estimation of the Importance of Condensed Particulate Matter to Ambient Particulate Levels*, U.S. EPA, NTIS PB84102565, April 1983.

EPA, 2007. *The U.S. Environmental Protection Agency RACT/BACT/LAER Clearinghouse*, 2007. http://cfpub.epa.gov/rblc

EQUILON, 2001. *Motiva Enterprises LLC, Equilon Enterprises LLC, and Deer Park Refining Limited Partnership Civil Judicial Settlement,* March 21, 2001.

GRACE Davidson, 2000. *Super DESOx ® − Providing Benchmark Effectiveness for SOx Reduction,* Dudley Sellery of Murphy Oil Corporation and Bob Riley of GRACE Davidson.

HORN, 1984. *Performance of Dry Flue Gas Desulfurization on a Petroleum Coke Kiln Application*, R.J. Horn of Ecolaire Environmental Company and J.F. Bent of Martin Marietta Aluminum, Journal of the Air Pollution Control Association, September 1984.

INTERCAT, 2002A. *Intercat SOXGETTER - SOx Reduction Additive Technology Overview*, March 27, 2002

INTERCAT, 2002B. *Ultra Lo-SOx – SOx Emission Control Agent*. www.intercatinc.com

LADCO, 2005. *Best Available Retrofit Technology (BARCT) for Selected Non-Electric Generating Units (EGU) Source Categories*, MACTEC Federal Programs, Inc. developed for Lake Michigan Air Directors Consortium (LADCO), June 28, 2005.

LADWP, 2005. The 2005 Urban Water Management Plan of the Los Angeles Department of Water and Power.

LINERO, 2006. *What's Up with Cement Plant Permitting?*, A.A. Linero, Florida Department of Environmental Potection, 2006.

MARAMA, 2007. *Assessment of Control Options for Petroleum Refineries in the Mid-Atlantic Region – Final Technical Support Document*. Prepared by MACTEC Federal Programs, Inc. for the Mid-Atlantic Regional Air Management Association (MARAMA), January 31, 2007.

MASSIE, 2005. *Catalysts for Lower Temperature Tail Gas Unit Operation.* S. Massie and C. Wilson of Criterion Catalysts & Technologies, presented at the Brimstone Sulfur Recovery Symposium, Vail, Colorado, September 2005.

MEYER, 2006. *Improving Sulfur Recovery Units*, S.F. Myer and C. Kulczycki of MECS, E. Juno of Sinclair Oil Corporation, and N. Watts of CEntry Constructors and Engineers, Petroleum Technical Quarterly, Quarter 3 of 2006.

NESCAUM, 2005. *Assessment of Control Technology Options for BART-Eligible Sources – Steam Electric Boilers, Industrial Boilers, Cement Plants, and Paper and Pulp Facilities*. Northeast States for Coordinated Air Use Management (NESCAUM) in partnership with the Mid-Atlantic Northeast Visibility Union (MANE-VU), March 2005.

NESCAUM, 2007, *Five-Factor Analysis of BARCT Eligible Sources – Survey of Options for Conducting BART Determinations*. Prepared by Northeast States for Coordinated Air Use Management (NESCAUM) for the Mid-Atlantic Northeast Visibility Union (MANE-VU), June 1, 2007.

NWCAA, 2006. *BP West Coast Products, LLC. Cherry Point Refinery Blaine, Washington, Air Operating Permit, Final Modification*. Northwest Clean Air Agency, September 06, 2006.

PECHAN, 2005. *Update of Control Equipment Data to Support Minnesota Pollution Control Agency (MPCA) Control Equipment Rule – Final Report*, Stephen M. Roe, Ying K. Hsu, Maggie Ma, Holly C. Linquist, E.H. Pechan & Associates, Inc., Report No. 05.06.00X/9446.000 CFMS No. A72995, June 2005.

PUGET, 2007. *Saint-Gobain Containers Glass Melting Furnaces.* E-mail from Gerry Pade, Engineer of Puget Sound Clean Air Agency to Minh Pham, Air Quality Specialist of SCAQMD, November 30, 2007.

TRIMER, 2007. *Treatment for Fine Particles and Gas Cloud Chamber® Technology and Its Applications.* K. Moss and R. Gravley, 2007.

VIERHEILIG, 2003. *The Role of Additives in Reducing Fluid Catalytic Cracking SOx and NOx Emissions*, Vierheilig, A. and Evans, M., Petroleum and Coal, Volume 45, 3-4, 147-153, 2003.

WEAVER, 2006. *Evaluating Wet Scrubbers*, Edwin H. Weaver with BELCO Technologies Corporation, Petroleum Technology Quarterly, Quarter 3, 2006.

WEST BASIN, 2008. West Basin Municipal Water District Strategic Business Plan, January 2008. http://www.westbasin.org/files/pdf/FINAL%20Strategic%20Business%20Plan%201-28-2008.pdf

WEST BASIN, 2005. West Basin Municipal Water District - 2005 Urban Water Management Plan http://www.westbasin.org/files/pdf/UWMP_2005.pdf

WEST BASIN, 2009. West Basin Municipal Water District – 2008-2009 Annual Report http://www.westbasin.org/files/pdf/2009-Water-Use-Report.pdf

WORLEYPARSONS, 2006. Sulfur Technology, Capability and Experience. WorleyParson.

Appendix A – ~~2005 RECLAIM~~ Emissions, RTC Holdings, and Initial Allocations

TABLE A-1
2005 SOx Emissions at SOx RECLAIM Facilities

Facility ID	Facility Name	Cycle	Emissions (tons per year)	Emissions (tons per day)	Cumulative Percentage
131003	BP WEST COAST PROD.LLC BP CARSON REFINERY	2	679.4	1.86	0.19
800363	CONOCOPHILLIPS COMPANY	2	421.2	1.15	0.3
114801	RHODIA INC.	1	410.7	1.13	0.42
800370	EQUILON ENTER., LLC, SHELL OIL PROD. U S	1	363.6	1	0.52
800030	CHEVRON PRODUCTS CO.	2	362.5	0.99	0.62
800089	EXXONMOBIL OIL CORPORATION	1	333.5	0.91	0.71
800026	ULTRAMAR INC	1	312.8	0.86	0.8
800362	CONOCOPHILLIPS COMPANY	1	210.7	0.58	0.85
131249	BP WEST COAST PRODUCTS LLC,BP WILMINGTON	1	130.1	0.36	0.89
800181	CALIFORNIA PORTLAND CEMENT CO	2	100.5	0.28	0.92
7427	OWENS-BROCKWAY GLASS CONTAINER INC	1	74.7	0.2	0.94
108701	SAINT-GOBAIN CONTAINERS, INC.	1	55.9	0.15	0.95
8547	QUEMETCO INC	1	37.3	0.1	0.96
124838	EXIDE TECHNOLOGIES	1	36.9	0.1	0.97
117247	EQUILON ENTERPRISES, LLC	1	31.2	0.09	0.98
800183	PARAMOUNT PETR CORP	1	22.6	0.06	0.99
35302	OWENS CORNING ROOFING AND ASPHALT, LLC	2	7.6	0.02	0.99
800264	EDGINGTON OIL COMPANY	2	6.7	0.02	0.99
115389	AES HUNTINGTON BEACH, LLC	2	6.4	0.02	1
40196	GUARDIAN INDUSTRIES CORP.	2	6.1	0.02	1
16642	ANHEUSER-BUSCH INC., LA BREWERY	1	5.4	0.01	1
42775	WEST NEWPORT OIL CO	1	2.3	0.01	1
119104	CALMAT CO	1	1.1	0	1
800182	RIVERSIDE CEMENT CO	1	0.7	0	1
21887	KIMBERLY-CLARK WORLDWIDE INC.-FULT. MILL	2	0.4	0	1
45746	PABCO BLDG PRODUCTS LLC,PABCO PAPER, DBA	2	0.1	0	1
800372	EQUILON ENTER. LLC, SHELL OIL PROD. US	2	0.1	0	1
		Total	**3621**	**9.92**	

(Note: There are 27 facilities out of total 33 facilities listed in this table. The remaining four facilities ~~have~~reported zero emissions in 2005.)

Total 2005 reported emissions = 9.92 tons per day
Total 2005 audited emissions = 10.04 tons per day

TABLE A-2
RTC Holdings and Initial Allocations for Compliance Year 2012 As Of August 29, 2009

11 Major Facilities

Count	Facility ID	Facility Name	RTC Holdings (tpd) CY2012	Initial Alloc (tpd) Int12alloc
1	131003	BP WEST COAST PROD.LLC BP CARSON REF.	1.47	0.86
2	800030	CHEVRON PRODUCTS CO.	1.21	0.86
3	800362	CONOCOPHILLIPS COMPANY	0.59	0.21
4	800363	CONOCOPHILLIPS COMPANY	1.38	0.78
5	800089	EXXONMOBIL OIL CORPORATION	1.15	0.50
6	800026	ULTRAMAR INC (NSR USE ONLY)	0.72	0.57
7	800436	TESORO REFINING AND MARKETING CO	1.20	0.52
8	131249	BP WEST COAST PRODUCTS LLC,BP WILMINGTON	0.84	0.84
9	800181	CALIFORNIA PORTLAND CEMENT CO (NSR USE)	0.27	0.22
10	7427	OWENS-BROCKWAY GLASS CONTAINER INC	0.31	0.68
11	114801	RHODIA INC.	1.07	1.12
		TOTAL	**10.21**	**7.16**

21 Remaining Facilities

Count	Facility ID	Facility Name	RTC Holdings (tpd) CY2012	Initial Alloc (tpd) Int12alloc
12	115389	AES HUNTINGTON BEACH, LLC	0.02	0.01
13	148236	AIR LIQUIDE LARGE INDUSTRIES U.S., LP	0.00	
14	16642	ANHEUSER-BUSCH INC., (LA BREWERY)	0.02	0.02
15	119104	CALMAT CO	0.00	
17	800264	EDGINGTON OIL COMPANY	0.02	0.02
18	800372	EQUILON ENTER. LLC, SHELL OIL PROD. US	0.00	1.04
19	124838	EXIDE TECHNOLOGIES	0.14	0.14
20	124808	INEOS POLYPROPYLENE LLC	0.00	
21	21887	KIMBERLY-CLARK WORLDWIDE INC.-FULT. MILL	0.00	0.00
22	800080	LUNDAY-THAGARD COMPANY	0.00	0.00
23	35302	OWENS CORNING ROOFING AND ASPHALT, LLC	0.03	0.03
24	45746	PABCO BLDG PRODUCTS LLC,PABCO PAPER, DBA	0.02	0.02
25	800183	PARAMOUNT PETR CORP (EIS USE)	0.13	0.11
26	8547	QUEMETCO INC	0.14	0.14
27	800182	RIVERSIDE CEMENT CO (EIS USE)	0.06	0.12
28	14944	TECHALLOY CO., INC.	0.01	0.01
29	151798	TESORO REFINING AND MARKETING CO	0.08	0.06
31	12185	US GYPSUM CO	0.01	0.01
32	42775	WEST NEWPORT OIL CO	0.03	0.86
		TOTAL	**0.73**	**2.60**

*CENCO & P.Q.CORP have Zero RTC Holdings

TABLE A-2 (Cont.)

Inactive Facilities				
33	40196	GUARDIAN INDUSTRIES CORP.	0.00	0.10
34	99588	DOMTAR GYPSUM INC	0.01	0.01
37	106797	SAINT-GOBAIN CONTAINERS, INC.	0.00	
38	108701	SAINT-GOBAIN CONTAINERS, INC.	0.00	
39	117247	EQUILON ENTERPRISES, LLC	0.00	
51	800184	GOLDEN WEST REF CO	0.00	0.21
52	800223	TEXACO REF & MARKETING INC	0.00	
		TOTAL	**0.01**	**0.32**

Investors			
35	101337	NATIONAL OFFSETS	0.00
36	104017	AERA ENERGY LLC	0.03
40	139796	CITY OF RIVERSIDE PUBLIC UTILITIES DEPT	0.02
41	140540	CALIFORNIA LNG PROJECT CORPORATION	0.00
42	152857	GEORGIA-PACIFIC GYPSUM LLC	0.00
43	700004	CANTOR FITZGERALD BROKERAGE, L.P.	0.00
44	700058	U S TRUST COMPANY, NATIONAL ASSOCIATION	0.00
45	700062	BRIAN ANDERSON	0.14
46	700122	GREY K ENVIRONMENTAL FUND, L.P.	0.49
47	700123	APEX PLASTICS & TOOLING, INC.	0.00
48	700128	GREY K FUND LP	0.00
49	700144	OLDUVAI GORGE, LLC	0.15
50	700153	TAUBER OIL COMPANY	0.00
		TOTAL	**0.83**

Total for active RECLAIM facilities	**11.77**	**10.08**

TABLE A-3
RTCs Available for RECLAIM Market from Shutdown Facilities

Facility ID	Name	Shutdown Compliance Year	Initial Allocations 2010+	2010+ Holding as of 8/26/2010	IYB RTC Available to Market (lbs)	IYB RTC Available to Market (tpd)
6281	US GOVT,MARINE CORPS AIR STATION,EL TORO	2000	1,892	0	1,892	0.00
6394	ANAHEIM FOUNDRY INC	1996	7,782	0	7,782	0.01
9141	CANNERS STEAM CO INC	2007	8,596	0	8,596	0.01
12912	LIBBEY GLASS INC	2004	71,816	0	71,816	0.10
18984	ANCHOR GLASS CONTAINER CORP	1994	136,016	0	136,016	0.19
40196	GUARDIAN INDUSTRIES CORP.	2007	71,882	0	71,882	0.10
60942	GAF BUILDING MATERIALS CORPORATION	1994	70,052	0	70,052	0.10
67945	GREAT WESTERN MALTING CO., INC.	2002	125,326	0	125,326	0.17
79397	OWENS-BROCKWAY GLASS CONTAINER INC	1996	102,445	0	102,445	0.14
99588	DOMTAR GYPSUM INC	1999	8,572	8,572	0	0.00
106797	SAINT-GOBAIN CONTAINERS, INC.	2004	235,558	0	235,558	0.32
108701	SAINT-GOBAIN CONTAINERS, INC.	2007	0	0	0	0.00
800047	FLETCHER OIL & REF CO	2000	42,094	0	42,094	0.06
800184	GOLDEN WEST REF CO	2001	150,557	243	150,314	0.21
800232	HUNT-WESSON INC	1996	9,564	0	9,564	0.01

Total from shutdown facilities (tons per day) **1.42**

From Glass Facilities (tpd) 0.85

TABLE A-~~2~~4
2005 SOx Emissions of Top Seven Groups of Equipment

Group	Fac Name	Description	Fuel Type	2005 Emissions (lbs)	2005 Emissions (tpd)
1	B	REGENERATOR, FCCU		755399.17	1.03
1	F	REGENERATOR, FCCU		447175.34	0.61
1	A	REGENERATOR		281211.84	0.39
1	D	REGENERATOR		195964.32	0.27
1	D	BOILER		30445.34	0.04
1	C	REGENERATOR		703085.36	0.96
1	E	REGENERATOR, FCCU		0	0.00
1	E	BOILER, CO WASTE HEAT, FCCU		181757.45	0.25
Total for 6 FCCUs					**3.55**
2	B	HEATER, CRUDE OIL DISTILLATION	REF_GAS	57649.9	0.08
2	D	BOILER	REF_GAS	25516.55	0.03
2	D	HEATER	REF_GAS	47760.79	0.07
2	D	FURNACE	REF_GAS	32123.51	0.04
2	C	HEATER	REF_GAS	76489.74	0.10
2	C	HEATER	REF_GAS	64590.83	0.09
2	C	BOILER	REF_GAS	45844.81	0.06
2	C	BOILER	REF_GAS	43162.12	0.06
2	C	HEATER	REF_GAS	30440.13	0.04
2	C	HEATER	REF_GAS	28672.09	0.04
2	C	HEATER	REF_GAS	27970.11	0.04
2	E	HEATER, COKING PROCESS	PROCESS GAS, REF GAS	48332.59	0.07
2	E	HEATER, CRUDE UNIT	PROCESS GAS, REF GAS	39770.77	0.05
2	E	HEATER, COKING PROCESS	PROCESS GAS, REF GAS	39577.84	0.05
2	E	BOILER, HYDROGEN GENERATION	REF GAS, NAT GAS	28868.34	0.04
2	E	BOILER, STEAM GENERATION	REF GAS, PROCESS GAS FROM SCRUBBER	26484.59	0.04
Total for 16 boilers/heaters (1 currently not in operation)					**0.91**
3	EE	INCINERATOR (C54), CONTROL EQUIP FOR ABSORBER OF SULFUR RECOVERY UNIT	REF GAS, NAT GAS, PROCESS GAS	32995.62	0.05
3	EE	INCINERATOR (C56), CONTROL EQUIP FOR ABSORBER OF SULFUR RECOVERY UNIT	REF GAS, NAT GAS, PROCESS GAS	11974.31	0.02
3	B	CONTROL DEVICE (C-910) THERMAL OXIDIZER	REFINERY GAS, NATURAL GAS, WASTE GAS	114337.58	0.16
3	B	CONTROL DEVICE, THERMAL OXIDIZER	REFINERY GAS, NATURAL GAS, WASTE GAS	111676.16	0.15
3	F	OXIDIZER		116994.68	0.16
3	A	THERMAL OXIDIZER (D927), TAIL GAS IN SULFUR PRODUCTION UNIT	NATGAS, REF GAS	75220.2	0.10
3	A	THERMAL OXIDIZER (D927), TAIL GAS IN SULFUR PRODUCTION UNIT	NATGAS, REF GAS	62774.65	0.09

TABLE A-~~2~~4 (Continued)

Group	Fac Name	Description	Fuel Type	2005 Emissions (lbs)	2005 Emissions (tpd)
	A	THERMAL OXIDIZER (D911), TAIL GAS IN SULFUR PRODUCTION UNIT	NATGAS, REF GAS	47309.99	0.06
	D	OXIDIZER		112186.65	0.15
	C	INCINERATOR (C456), SULFUR RECOVERY UNIT NO 2, TAIL GAS INCINERATOR	REF GAS, NAT GAS	7518.47	0.01
	C	INCINERATOR (C436), SULFUR RECOVERY UNIT NO 1, TAIL GAS INCINERATOR	REF GAS, NAT GAS	7005.95	0.01
Total for 11 SRU/Tail Gas Units					**0.96**
	B	FURNACE, SULFURIC ACID PLANT	FUELOIL, NAT_GAS, SULFUR	821456.88	1.13
	A	REACTOR, SULFURIC ACID PRODUCTION, COMBUSTION CHAMBER	PROCESS GAS	28304	0.04
	A	REACTOR, SULFURIC ACID PRODUCTION, COMBUSTION CHAMBER	REFGAS, NATGAS	443.05	0.00
Total for 3 Sulfuric Acid Manufacturing Reactors/Furnace					**1.16**
	BG	FURNACE	NAT_GAS	55242.68	0.08
	BG	FURNACE, MELTING	NAT_GAS, OXY-FUEL, PROPANE, GLASS	61637.19	0.08
	BG	FURNACE, MELTING	NAT_GAS, OXY-FUEL, PROPANE, GLASS	26411.28	0.04
	SG	FURNACE, MELTING	FUEL OIL, NAT_GAS, OXY FUEL, GLASS	93706.37	0.13
Total for 4 Container Glass Melting Furnaces					**0.32**
	BW	KILN, ROTARY, CALCINER PET COKE	NATURAL GAS, DIESEL FUE:	257392.34	0.35
Total for 1 coke calciner					**0.35**
	CC	KILN	COAL, COKE, FUEL OIL, NAT GAS, TIRE	140815.54	0.19
	CC	KILN	COAL, COKE, FUEL OIL, NAT GAS, TIRE	54045.06	0.07
	CC	BOILER, STEAM GENERATION, CIRCULATING FLUIIZED BED	COAL, COKE, NAT GAS	1561.82	0.00
Total for 2 cement kilns					**0.27**
TOTAL 7 CATEGORIES OF EQUIPMENT					**7.53**

Appendix B – Summary of Federal, State and Local SOx Rule Requirements

(Summarized by Kevin Orellana)

Fluid Catalytic Cracking Units

Rule/Regulation	**Applicability**	**Emission Limits**	**Compliance Date**	**Monitoring ****
SCAQMD R1105	FCCU	132 lbs SO_2 per 1000 bbl feed (60-minute average)	1/1/1987	
BAAQMD 9-1	FCCU	1000 ppmv SO_2	3/15/1995	CEMS
San Diego County APCD R53	Other sources of gaseous sulfur emissions where sulfur compounds emitted are not products of fuel combustion	0.05 % by volume dry, sulfur as SO_2	1/22/1997	
NSPS 40 CFR Part 60 Subpart Ja	FCCU	25 ppmv SO_2 dry basis, 365-day rolling average	5/14/2007	CEMS

Sulfur Recovery Units/Tail Gas Units

Rule/Regulation	**Applicability**	**Emission Limits**	**Compliance Date**	**Monitoring ****
SCAQMD R468	SRU	500 ppm sulfur compounds (calculated as SO_2 dry) over 15 minute average; and 10ppm H_2S over 15-minutes (dry); and 198.5 lbs./hr sulfur compounds as SO_2	10/8/1976	
BAAQMD 9-1	SRU	250 ppmv SO_2 dry @ 0% O_2	3/15/1995	CEMS
San Diego County APCD R53	Sulfur recovery plants	0.05% by volume dry, sulfur as SO_2	1/22/1997	
NSPS 40 CFR Part 60 Subpart Ja	SRU with capacity >20 long tons/day, followed by incineration	250 ppmv SO_2 dry @ 0% O_2	5/14/2007	CEMS
NSPS 40 CFR Part 60 Subpart Ja	SRU with capacity >20 long tons/day, followed by incineration, with multiple trains or release points	250 ppmv SO_2 dry @ 0% O_2 for each process train or release point; or comply with a flow-weighted average of 250 ppmv for all release points	5/14/2007	CEMS
NSPS 40 CFR Part 60 Subpart Ja	SRU with capacity >20 long tons/day, not followed by incineration	10 ppmv H_2S and 300 ppmv of reduced sulfur compounds (H_2S, COS, and CS_2), each calculated as ppmv of SO_2 dry @ 0% O_2	5/14/2007	CEMS

Refinery Boilers/Heaters

Rule/Regulation	Applicability	Emission Limits	Compliance Date	Monitoring **
NSPS 40 CFR Part 60 Subpart Ja	Fuel gas combustion devices	162 ppmv H_2S in fuel gas determined hourly on a 3-hour rolling average basis or 60 ppmv in fuel gas determined daily on a 365 successive calendar day rolling average basis	5/14/2007	CFGMS
NSPS 40 CFR Part 60 Subpart Ja	Fuel gas combustion devices	20 ppmv flue gas SO_2 (dry @ 0% O_2) determined hourly on a 3-hour rolling average basis, and 8 ppmv flue gas SO2 (dry @0% O2) determined daily on a 365 successive calendar day rolling average basis	5/14/2007	CEMS
SCAQMD R431.1	Fuel gas combustion devices	40 ppmv averaged over 4 hours, calculated as H_2S	5/4/1994	CFGMS or CEMS
SJVUAPCD R4301	Fuel burning equipment	200 lb/hr sulfur compounds, calculated as SO_2	12/17/1992	

Coke Calciners

Rule/Regulation	Applicability	Emission Limits	Compliance Date	Monitoring **
SCAQMD R1119	Coke Calcining	At least 80% reduction of uncontrolled SOx emissions	7/1/1983	
BAAQMD 9-1	Coke Calcining kilns	400 ppmv or 250 lb/hr SO_2	3/15/1995	
San Diego County APCD R53	Other sources of gaseous sulfur emissions where sulfur compounds emitted are not products of fuel combustion	0.05 % by volume dry, sulfur as SO_2	1/22/1997	

Sulfuric Acid Plants

Rule/Regulation	Applicability	Emission Limits	Compliance Date	Monitoring **
SCAQMD R469	Sulfuric Acid	500 ppm sulfur compounds (calculated as SO_2 dry) over 15 minute average; 198.5 lbs./hr sulfur compounds as SO_2	2/13/1981	
BAAQMD 9-1	Sulfuric acid plant equipment	300 ppmv SO_2 @12% O_2	3/15/1995	CEMS
San Diego County APCD R53	Other sources of gaseous sulfur emissions where sulfur compounds emitted are not products of fuel combustion	0.05 % by volume dry, sulfur as SO_2	1/22/1997	
NSPS 40 CFR Part 60 Subpart H	Sulfuric Acid production units	4 lb SO_2 per ton of acid produced (as 100% H_2SO_4)	6/14/1974	CEMS

Cement Kilns

Rule/Regulation	Applicability	Emission Limits	Compliance Date	Monitoring **
San Diego County APCD R53	Other sources of gaseous sulfur emissions where sulfur compounds emitted are not products of fuel combustion	0.05 % by volume dry, sulfur as SO_2	1/22/1997	
SJVUAPCD R4801	Any equipment that discharges gaseous sulfur compounds	0.2% by volume SO_2 dry, over 15 min-average	12/17/1992	

Glass Manufacturing

Rule/Regulation	Applicability	Emission Limits	Compliance Date	Monitoring **
San Diego County APCD R53	Other sources of gaseous sulfur emissions where sulfur compounds emitted are not products of fuel combustion	0.05 % by volume dry, sulfur as SO_2	1/22/1997	
SJVUAPCD R4354	Glass melting furnaces	0.90 lb SOx per ton glass produced (rolling 30-day average)	1/1/2011	CEMS

Information related to the U.S. EPA Consent Decree for FCCUs are summarized below:

Emission Limits	**Compliance Date**	**Monitoring**
BP: 50 ppmv SO_2 @ 0% O_2, 365-day rolling average; 150 ppmv SO_2 @ 0% O_2, 7-day rolling average	7/11/2005	CEMS
Tesoro: 36.2 ppmv SO_2 @ 0% O_2, 365-day rolling average; 69.1 ppmv SO_2 @ 0% O_2, 7-day rolling average	2/2/2006	CEMS
Valero: No set limit at this time due to an ongoing demonstration project with SO_2 reducing catalysts due by the compliance date.	4/30/2011	CEMS
ExxonMobil: 25 ppmv SO_2 @ 0% O_2, 365-day rolling average; 50 ppmv SO_2 @ 0% O_2, 7-day rolling average	12/13/2005	CEMS
Chevron: 25 ppmv SO_2 @ 0% O_2, 365-day rolling average; 50 ppmv SO_2 @ 0% O_2, 7-day rolling average	12/31/2005	CEMS
ConocoPhillips: 25 ppmv SO_2 @ 0% O_2, 365-day rolling average; 50 ppmv SO_2 @ 0% O_2, 7-day rolling average	3/1/2011	CEMS

Appendix C – CEMS Information & Source Test Data

Table C-1: CEMS Data from a Refinery in the District – FCCU with Wet Gas Scrubber

SOx Emissions lbs/day	Day
111.09	9/13/08
111.02	9/14/08
110.09	9/15/08
109.51	9/16/08
110.36	9/17/08
119.47	9/18/08
129.49	9/19/08
130.41	9/20/08
130.88	9/21/08
130.75	9/22/08
130.93	9/23/08
131.86	9/24/08
130.62	9/25/08
130.69	9/26/08
125.6	9/27/08
132.65	9/28/08
131.76	9/29/08
128.53	9/30/08
127.41	10/1/08
129.48	10/2/08
131.67	10/3/08
132.49	10/4/08
131.92	10/5/08
131.33	10/6/08
131.02	10/7/08
119.64	10/8/08
154.21	10/9/08
154.71	10/10/08
155.74	10/11/08
156.58	10/12/08
146.18	10/13/08
128.23	10/14/08
132.85	10/15/08
140.19	10/16/08
139.43	10/17/08
140.03	10/18/08
140.16	10/19/08
143.02	10/20/08

SOx Emissions lbs/day	Day
145.23	10/21/08
143.99	10/22/08
143.19	10/23/08
143.22	10/24/08
143.55	10/25/08
143.89	10/26/08
143.61	10/27/08
143.3	10/28/08
143.92	10/29/08
143.73	10/30/08
139.91	10/31/08
130.97	11/1/08
131.45	11/2/08
133.77	11/3/08
131.73	11/4/08
131.32	11/5/08
130.27	11/6/08
132.76	11/7/08
137.1	11/8/08
138.25	11/9/08
138.12	11/10/08
137.22	11/11/08
137.09	11/12/08
137.11	11/13/08
136.91	11/14/08
135.62	11/15/08
135.75	11/16/08
135.71	11/17/08
136.19	11/18/08
137.07	11/19/08
137.4	11/20/08
137.14	11/21/08
137.25	11/22/08
137.81	11/23/08
134.1	11/24/08
125.09	11/25/08
122.53	11/26/08
122.32	11/27/08
122.14	11/28/08
122.55	11/29/08

SOx Emissions lbs/day	Day
122.9	11/30/08
125.16	12/1/08
124.33	12/2/08
123.61	12/3/08
123.43	12/4/08
123.25	12/5/08
122.44	12/6/08
123.13	12/7/08
125	12/8/08
123.15	12/9/08
122.73	12/10/08
122.37	12/11/08
123.49	12/12/08
123.68	12/13/08
135.92	12/15/08
139.17	12/16/08
134.89	12/17/08
135.66	12/18/08
129.8	12/19/08
130.95	12/20/08
138	12/21/08
132.16	12/22/08
125.81	12/23/08
134.23	12/24/08
155.32	12/25/08
156.05	12/26/08
156.06	12/27/08
157.29	12/28/08
157.07	12/29/08
155.95	12/30/08
157.3	12/31/08
160.33	1/1/09
155.22	1/2/09
141.5	1/3/09
144	1/4/09
147.65	1/5/09
143.59	1/6/09
141.79	1/7/09
154.11	1/8/09
156.96	1/9/09

SOx Emissions lbs/day	Day
150.46	1/10/09
150.58	1/11/09
153.81	1/12/09
155.46	1/13/09
157.15	1/14/09
157.49	1/15/09
157.24	1/16/09
158	1/17/09
149.89	1/18/09
147.05	1/19/09
145.6	1/20/09
146.31	1/21/09
145.74	1/22/09
150.03	1/23/09
158.61	1/24/09
157.7	1/25/09
158.07	1/26/09
158.49	1/27/09
157.81	1/28/09
154.73	1/29/09
153.98	1/30/09
155.43	1/31/09
157.58	2/1/09
155.16	2/2/09
156.07	2/3/09
155.67	2/4/09
156.76	2/5/09
156.1	2/6/09
158.64	2/7/09
159.41	2/8/09
155.14	2/9/09
160.87	2/10/09
157.97	2/11/09
151.77	2/12/09
148.28	2/13/09
143.42	2/14/09
145.05	2/15/09
150.44	2/16/09
149.17	2/17/09
145.34	2/18/09

SOx Emissions lbs/day	Day
144.16	2/19/09
143.64	2/20/09
144.62	2/21/09
145.55	2/22/09
149.61	2/23/09
155.25	2/24/09
156.9	2/25/09
153.88	2/26/09
156.03	2/27/09
155.04	2/28/09
143.39	3/1/09
139.42	3/2/09
141.21	3/3/09
141.9	3/4/09
141.2	3/5/09
142.64	3/6/09
143	3/7/09
142.89	3/8/09
142.7	3/9/09
141.86	3/10/09
111.54	3/11/09
48.03	3/12/09
118.74	3/13/09
36.04	3/14/09
136.91	3/15/09
143.78	3/16/09
142.9	3/17/09
125.63	3/18/09
118.51	3/19/09
119	3/20/09
122.27	3/21/09
130.06	3/22/09
133.4	3/23/09
134.39	3/24/09
136.13	3/25/09
136.69	3/26/09
136.46	3/27/09
136.49	3/28/09
138.11	3/29/09
136.85	3/30/09

SOx Emissions lbs/day	Day
134.63	3/31/09
136.42	4/1/09
136.65	4/2/09
138.37	4/3/09
	4/5/09
181.74	4/6/09
182.97	4/7/09
174.53	4/8/09
152.39	4/9/09
127.02	4/10/09
126.22	4/11/09
130.46	4/12/09
149.2	4/13/09
152.12	4/14/09
150.03	4/15/09
150.28	4/16/09
148.51	4/17/09
147.04	4/18/09
145.98	4/19/09
146.36	4/20/09
147.47	4/21/09
148.87	4/22/09
148.24	4/23/09
149.37	4/24/09
143.4	4/25/09
125.06	4/26/09
125.5	4/27/09
131.39	4/28/09
138.27	4/29/09
138.9	4/30/09
147.53	5/1/09
148.7	5/2/09
149.37	5/3/09
149.34	5/4/09
148.97	5/5/09
148.51	5/6/09
148.66	5/7/09
149.02	5/8/09
149.51	5/9/09
149.32	5/10/09

SOx Emissions lbs/day	Day
149.71	5/11/09
149.85	5/12/09
149.85	5/13/09
149.82	5/14/09
149.47	5/15/09
149.11	5/16/09
149.16	5/17/09
149	5/18/09
	5/19/09
150.05	5/20/09
150.46	5/21/09
150.32	5/22/09
149.93	5/23/09
149.89	5/24/09
150.07	5/25/09
149.87	5/26/09
149.28	5/27/09
149.69	5/28/09
149.55	5/29/09
149.49	5/30/09
148.77	5/31/09
147.92	6/1/09
148.77	6/2/09
148.87	6/3/09
148.31	6/4/09
148.7	6/5/09
149.28	6/6/09

The concentration during 265 days (8.83 months) is 3.80 ppmv, however this refinery reported emissions based on a level of 5 ppmv.

Table C-2: Source Test from a Refinery in the District - FCCU with Wet Gas Scrubber

Test/Run ID		1	2	3	Average	
Date Tested	NA	10/8/2008	10/9/2009	10/9/2008		
Stack Oxygen	%	1.30	1.28	1.27	1.28	
Stack Carbon Dioxide	%	17.8	17.7	17.9	17.82	
Average Stack Volumetric Flow (Methods 5 and 6)	dscfm	128,982	128,276	124,384	127214	
Stack Temperature (Methods 5 and 6)	oF	134	132	132	132.88	
Stack Moisture Concentration (Methods 5 and 6)	%	15.29	14.53	14.39	14.73	
FCC Feed	MBPD	49.19	48.93	48.93	49.02	
FCC Feed	MBPH	2.05	2.04	2.04	2.04	
Coke Make (Burn)	lb/hr	39,274	39,389	39,389	39,351	
Coke Make (Burn)	Mlb/hr	39.27	39.39	39.39	39.35	
Catalyst Circulation Rate	ton/min	45.41	46.25	46.25	45.97	
Gas Flow to Scrubber/Circulation Ratio	gal/MACF	26.23	25.94	25.94	26.04	
Total WESP Power	KW	7.49	8.06	8.06	7.87	
#2 Lower WESP Spark Rate	spk/min	1.34	1.30	1.30	1.31	
#1 Lower WESP Spark Rate	spk/min	2.37	4.08	4.08	3.51	
#2 Upper WESP Spark Rate	spk/min	0.00	0.00	0.00	0.00	
#1 Upper WESP Spark Rate	spk/min	0.00	0.00	0.00	0.00	
Oxides of Nitrogen as NO_2 - Method 100.1						LIMIT(S)
as found	ppmv	12.1	18.4	17.8	16.08	
at 3% O_2	ppmv	11.0	16.8	16.2	14.7	
at 0% O_2%	ppmv	12.9	19.6	18.9	17.1	20
emission rate	ppmv	11.3	17.2	16.1	14.9	
Carbon Monoxide – Method 100.1						
as found	ppmv	40.9	39.6	43.5	41.3	
at 3% O_2	ppmv	37.4	36.1	39.7	37.7	
emission rate	lbs/hr	23.4	22.5	24.0	23.3	
VOC as Total Gaseous Non-Methane Organic – Method 25.3						
VOC as TOC in Impinger Vial - Sample A	ppmv	0.63				
VOC as TGNMO in Canister - Sample A	ppmv	50.1				
Combined Vial and Canister Conc. - Sample A	ppmv	50.73				
VOC as TOC in Impinger Vial - Sample B	ppmv	0.28				
VOC as TGNMO in Canister - Sample B	ppmv	65.9				
Combined Vial and Canister Conc. - Sample B	ppmv	66.18				
as found-Average	ppmv	**58.46**				
at 3% O_2	ppmv	53.39				
emission rate	lbs/hr	19.07				
Sulfur Oxides as SO_2 – SCAQMD Method 6.1						
Stack Volumetric Flow	dscfm	128.071	123.830	121.962	124.621	
Isokinetic Sampling Rate (I)	%	98	93	92	94	90<=I<=110
Stack Moisture Concentration	%	15.97	15.44	15.18	15.53	
Stack Temperature oF	°F	135	132	132	133	
Corrected Gas Volume Collected	dscf	68.622	52.361	50.731	57.238	
SOx Conc. in Gas Sample	ppmv	1.270	0.810	0.706	0.929	
SOx Conc. in Gas Sample at 3% O_2	ppmv	1.160	0.739	0.644	0.848	
SOx Conc. in Gas Sample at 0% O_2	**ppmv**	**1.354**	**0.863**	**0.752**	**0.990**	25
SOx Emission Rate	lb/hr	1.65	1.02	0.87	1.18	
SOx Emission (lb/1000 coke burn)	lb/MB	0.04	0.03	0.02	0.03	9.80
Stack Particulate Matter (PM) – EPA Method 5 (Front ½)SCAQMD Method 5.2 (Back ½)						
Stack Volumetric Flow	dscfm	129,892	132,722	126,806	129,807	
Isokinetic Sampling Rate (I)	%	103	104	102	103	90<=I<=110
Stack Moisture Concentration	%	14.60	13.61	13.59	13.93	
Stack Temperature oF	°F	134	132	133	133	
Corrected Gas Volume Collected	dscf	183.457	189.314	177.602	183.458	
Stack Total PM Mass	mg	42.60	34.55	34.45	37.20	
Stack Total PM - as found	gr/dscf	0.00358	0.00282	0.00299	0.00313	
Stack Total PM at 3% O_2	gr/dscf	0.00327	0.00257	0.00273	0.00286	
Stack Total PM emission rate	lb/hr	3.99	3.20	3.25	3.48	
Stack Solid PM Mass	mg	42.60	31.80	31.95	35.45	
Stack Solid PM - at found	gr/dscf	0.00358	0.00259	0.00278	0.00298	
Stack Solid PM at 3% O_2	gr/dscf	0.00327	0.00236	0.00253	0.00272	
Stack Solid PM Emission Rate	lb/hr	3.99	2.95	3.02	3.32	
Stack PM Emission (lb/1000 bbl of feed)	lb/MB	1.96	1.57	1.60	1.70	2.80
Stack PM Emission (lb/1000 coke burn)	lb/MB	0.10	0.08	0.08	0.09	1.00

Table C-2: Source Test from a Refinery in the District - FCCU with Wet Gas Scrubber (Cont.)

Inlet Particulate Matter (PM) – EPA Method 5						
Inlet Volumetric Flow	dscf	102,640	108,052	116,160	108,951	
Isokinetic Sampling Rate (I)	%	92	103	92	96	90<=I<=110
Inlet Moisture Concentration	%	16.39	16.10	10.20	14.23	
Inlet Temperature	°F	561	570	567	566	
Corrected Gas Volume Collected	dscf	27.307	32.356	30.980	30.214	
Inlet Total PM Mass	mg	169.90	229.75	330.30	243.32	
Inlet Total PM - as found	gr/dscf	0.09602	0.10958	0.16454	0.12338	
Inlet Total PM at 3% O_2	gr/dscf	0.08770	0.09996	0.15006	0.11257	
Inlet PM emission rate	lb/hr	84.47	101.49	163.82	116.59	

Appendix D – Survey Questionnaires

Staff developed two Survey Questionnaires to collect information for this rule making process. The first Survey was sent out in 2008, and the second set of Survey was sent out in 2009. Please see below.

SOx RECLAIM - SURVEY QUESTIONNAIRE
July 23, 2009

Please provide the following information by August 7, 2009.

Water

1. What is the current water usage and distribution at your facility (e.g. xx gal/year (xx%) used in cooling tower, xx gal/year (xx%) used in refinery processes)?

2. Who is the water supplier for your facility? Does your facility have a maximum cap on the amount of water (fresh and recycled) that the facility can purchase from the supplier? If yes, please specify.

3. How many groundwater wells does your facility have? How much is your facility permitted to pump and how much is your facility currently pumping? Please provide a copy of the groundwater permit for your facility.

Wastewater

1. Your facility may own and operate its own wastewater treatment facility. What is the maximum capacity of this wastewater treatment facility? What is the normal rate of wastewater that your facility is currently handling? Please provide a brief description and schematic of the process.

2. After treating the wastewater within your facility, where does the facility discharge the wastewater to?

3. Does the facility send the wastewater to a third party for further treatment? If yes, who is this third party and what are the average and maximum amount sent to this third party treatment facility? Is there any limit to the amount that your facility can send?

4. Does your facility purchase recycled water to use in the processes at your facility? If yes, who is the supplier and what are the average and maximum amount that can be purchased?

5. Who is the wastewater regulator for your facility? Please provide us a copy of your facility's wastewater discharge permits.

Solid Waste

1. How does the refinery currently handle the catalyst fines from the ESPs? Where are they shipped (or sold) to and what is the quantity? Are they considered hazardous waste?

2. Who is the solid waste regulator for your facility? If your facility is subject to certain requirements on solid waste discharge, please provide a copy of the permits.

South Coast Air Quality Management District

SURVEY QUESTIONNAIRE
FOR PROPOSED AMENDED REGULATION XX
FURTHER SOx REDUCTION FOR RECLAIM
(Request Due Date – February 21, 2008)

Facility Contact

1. Please provide the facility contact for this project:

   Name: ____
   Title: ____
   Phone Number: ____
   Email Address: ____________________________________

Facility Top SOx Emitters

2. Please list the top 10 SOx emitters at your facility and provide the following information.

   — Device description and device identification number
   — Emissions (tons per day) in 2005, 2006, 2007
   — SOx control technology used

Operational Data

3. Please provide the following information for the following seven specific equipment categories if they are on your facility's list of top ten SOx emitters.

   Fluid Catalytic Cracking Units (FCCUs)

a) Please provide the following information:

   — Feed rate, average and range (thousands barrels per day)
   — Sulfur content of feed, average and range (percent by weight)
   — Coke burn-off rate, average and range (thousand pounds per hour)
   — FCCU catalyst manufacturer and catalyst recirculation rate (tons per hour)
   — Average and range of flue gas exhaust flow rate from regenerator (millions dry standard cubic feet) and exhaust temperatures (degree Fahrenheit)
   — Average and range of SOx concentration in the exhaust flue gas from the FCCU regenerator (ppmv at %O_2)

b) Does the facility currently use FCCU SOx reduction catalysts? If yes, please provide the following information:

   — Name of catalyst manufacturer and name of SOx reduction catalyst
   — Usage rate (pounds of catalysts added per day, or pounds of catalyst per pound of FCCU catalyst)
   — Baseline SOx emissions and control efficiency. If available, please submit a copy of manufacturer's quote including specifications and guarantee
   — Costs of SOx reduction catalysts. Please provide annual operating costs and any modification costs to the FCCU if needed in order to use the SOx reduction catalysts.
   — When were the SOx reduction catalysts first used in the FCCUs and how long has the facility been using SOx reduction catalysts?

c) Does the facility currently use, or plan to use, post combustion control device (e.g. wet scrubber)? If yes, please provide the following information:

- Brief description of the technology (e.g. scrubber)
- Design parameters (e.g. maximum flue gas flow rate, type of absorbent, absorbent flow rate, control efficiency, inlet and outlet ppmv, emission rate)
- Capital costs and annual operating costs for the control technology
- Installation date (or age of equipment)

d) Please provide the most current source testing information (e.g. inlet and outlet ppmv, control efficiency, flue gas flow rate, emission rate, and test method). Please submit a copy of test reports or results if possible.

Refinery Boilers, Refinery Heaters & Coal-Fired Fluidized Bed Boilers

a) Please provide the following information:

- Type of fuel used and fuel usage rate, range and average
- Sulfur content of fuel, range and average (percent by weight or ppmw)
- Flue gas exhaust flow rate, range and average (millions dry standard cubic feet)
- Annual average and range of the SOx concentrations in the exhaust flue gas (ppmv at 3%O2)

b) Does the facility currently use any SOx control technology for the boiler/heater? If yes, please provide the following information:

- Brief description of the technology (e.g. scrubber)
- Design parameters (e.g. maximum flue gas flow rate, absorbent flow rate, control efficiency, inlet and outlet ppmv, emission rate)
- Capital costs and annual operating costs for the control technology
- Installation date (or age of equipment)

c) Please provide the most current source testing information (e.g. inlet and outlet ppmv, control efficiency, flue gas flow rate, emission rate, and test method). Please submit a copy of test reports or results if possible.

Sulfur Recovery & Tail Gas Treatment Units

a) Please provide the following information on the current operational data of the sulfur recovery and tail gas treatment units, including the thermal oxidizers, if appropriate:

- Brief description of the sulfur recovery & tail gas treatment unit including device identification number of the units in the system
- Current design and actual capacity of the sulfur recovery & treatment unit, range and average
- Sulfur content of feed, range and average (percent by volume or ppmv)
- Current sulfur removal efficiency of the system, and method used to determine the sulfur removal efficiency
- Flue gas exhaust flow rate, range and average (millions dry standard cubic feet)
- Annual average and range of the SOx concentrations in the exhaust flue gas
- Installation date (or age of equipment)

b) Please provide the most current source testing information (e.g. inlet and outlet ppmv, control efficiency, flue gas flow rate, emission rate, and test method). Please submit a copy of test reports or results if possible.

Sulfuric Acid Manufacturing Process

a) Please provide the following information:

- Brief description of the basic and control technique/equipment in the sulfuric acid manufacturing process (e.g. furnace, waste heat boiler, catalytic converter, ESP, absorber, scrubber etc) including device identification number
- Design and actual production rate (tons of acid produced)
- Type and input rate of raw materials (e.g. spent sulfuric acid, sulfur)
- Flue gas exhaust flow rate, range and average, (millions dry standard cubic feet)
- Range and average of SOx concentrations in the exhaust flue gas (ppmv)
- Annual average SOx emission rate (lbs SOx per ton of acid produced)

b) Does the facility currently use SOx control technology for the process? If yes, please provide the following information:

- Brief description of the technology (e.g. dual absorption, wet gas scrubber)
- Design parameters (e.g. maximum flue gas flow rate, absorbent flow rate, control efficiency, inlet and outlet ppmv, emission rate)
- Capital costs and annual operating costs for the control technology
- Installation date (or age of equipment)

c) Please provide the most current source testing information (e.g. inlet and outlet ppmv, control efficiency, flue gas flow rate, emission rate, and test method). Please submit a copy of test reports or results if possible.

Container Glass Manufacturing Process – Melting Furnace

a) Please provide the following information:

- Design and actual capacity of each furnace (mmbtu/hr and tons of glass pulled)
- Type and input rate of raw materials (e.g. limestone, soda ash, cullet)
- Flue gas exhaust flow rate, range and average (millions dry standard cubic feet)
- Annual average and range of SOx concentrations in the exhaust flue gas (ppmv)
- Annual average emission rate for SOx (lbs SOx per ton of glass pulled)

b) Does the facility currently use SOx control technology for the process? If yes, please provide the following information:

- Brief description of the technology (e.g. scrubber)
- Design parameters (e.g. maximum flue gas flow rate, absorbent flow rate, control efficiency, inlet and outlet ppmv, emission rate)
- Capital costs and annual operating costs for the control technology
- Installation date (or age of equipment)

c) Please provide the most current source testing information (e.g. inlet and outlet ppmv, control efficiency, flue gas flow rate, emission rate, and test method). Please submit a copy of test reports or results if possible.

Coke Calcining Kiln

a) Please provide the following information on the current operational data of the coke calciner (kiln):

- Maximum and average feed rate (tons per year and per day of green coke)
- Maximum and average production rate (tons per year and per day of calcined coke)
- Type of fuel used, and maximum and average fuel usage rate
- Maximum and average flue gas exhaust flow rate (millions dry standard cubic feet and) and stack temperatures (degree Fahrenheit)
- Range of outlet SOx concentrations (ppmv at % O_2) and annual average
- Annual average SOx emission rate (lbs SOx per ton of glass pulled)

b) Does the facility currently use SOx control technology for the process? If yes, please provide the following information:

- Brief description of the technology (e.g. dry scrubber)
- Design parameters (e.g. production rate, maximum treated flue gas, absorbent flow rate, control efficiency, inlet and outlet ppmv, emission rate in lbs SOx per ton coke)
- Capital costs and annual operating costs for the control system
- Installation date (or age of equipment)

c) Please provide the most current source testing information (e.g. inlet and outlet ppmv, control efficiency, flue gas flow rate, emission rate, and test method). Please submit a copy of test reports or results if possible.

Portland Cement Kiln

a) Please provide the following information on the current operational data of the Portland cement kiln

- Maximum and average feed rate of raw materials (tons per year and per day)
- Maximum and average production rate (tons per year and per day of calcined coke)
- Type of fuel used, and maximum and average fuel usage rate
- Maximum and average flue gas exhaust flow rate (millions dry standard cubic feet and) and stack temperatures (degree Fahrenheit)
- Range of outlet SOx concentrations (ppmv at % O_2) and annual average

b) Does the facility currently use any SOx control technology for the process? If yes, please provide the following information:

- Brief description of the technology (e.g. dry scrubber)
- Design parameters (e.g. production rate, maximum treated flue gas, absorbent flow rate, control efficiency, inlet and outlet ppmv, emission rate in lbs SOx per ton coke)
- Capital costs and annual operating costs for the control system
- Installation date (or age of equipment)

c) Please provide the most current source testing information (e.g. inlet and outlet ppmv, control efficiency, flue gas flow rate, emission rate, and test method). Please submit a copy of test reports or results if possible.

Reports Submitted Under the U.S. EPA Consent Decree

4. If the facility must implement any control technology to further reduce SOx under a consent decree with the U.S. Environmental Protection Agency (EPA), please provide the District a copy of all reports and test results that the facility has been submitted to EPA on this subject.

Other Feasible Control Technology

5. Please provide the following information on any feasible control technology that could further reduce SOx from the above seven categories of equipment.

- A brief description of the technology, manufacturer's name, and control efficiency
- If available, estimated equipment costs, annual operating costs, cost effectiveness analysis, manufacturer's specifications, and guarantee
- If available, the facility’s name that currently uses or will use this technology.

If you have any questions on the Survey Questionnaire, please contact:
Minh Pham, P.E.
Air Quality Specialist
Phone: (909) 396-2613
Email: mpham@aqmd.gov

Appendix E – Analysis for Rule 1105.1 Costs.

Note that to protect confidentiality, staff used different letters/numbers to refer to the different refineries and these are not the same as the letters/numbers used in the Staff Report of SOx RECLAIM and the Staff Report of Rule 1105.1.

After Rule 1105.1 was adopted in November 3, 2003, the refineries installed control equipment to meet the PM10 and ammonia emission standards of Rule 1105.1. Four refineries selected to install dry electrostatic precipitators (ESPs) and one refinery installed a combination of a wet gas scrubber and a wet electrostatic precipitator (WGS/WESP). A summary of the control equipment manufacturers, contractors, construction period, and reported costs by the refineries is shown in below. Staff's analysis comparing the reported costs and the estimated costs during the rule development is summarized below.

Refinery		Manufacturers	Contractors	Construction Period	Reported Costs
K	ESP	Hamon Research Cottrell	Davenport Engineering	12/2007 – 05/2009	$ 44 M
Y	ESP	Hamon Research Cottrell	Jacobs Engineering	10/2007 – 01/2009	$ 340 M
M	ESP	Hamon Research Cottrell	Hamon Research Cottrell	1993	$ 23 M
W	ESP	Hamon Research Cottrell	Hamon Research Cottrell	2007 - 2008	$ 121 M
X	WGS/WESP	ExxonMobil	Jacobs Engineering	07/2007 – 09/2008	$ 59 M
L	ESP	Hamon Research Cottrell	Jacobs Engineering	11/2006 – 08/2008	$ 102 M
				Total	$ 666 M

Refinery K

During the development of Rule 1105.1 in 2003, Refinery K indicated that they did not have enough space to install dry ESPs but planned to install a WGS to comply with the proposed rule. Refinery K developed a cost estimate for the project including a BELCO WGS, a purge treatment unit, and induced draft fan to overcome pressure drop, a gas-to-gas heat exchanger to reheat the plume, and a wastewater treatment unit to handle the waste. The estimated costs for the project were $68 million dollars. A consultant hired by WSPA, NEXANT, reviewed the costs estimated by Refinery K, and added additional costs for demolition, modification of the SRU/TGs, electrical substation, and wastewater treatment, tie-in costs for NOx control, paving, and opportunity lost costs for extended turnaround. The result was an estimate of $78.7 million dollars capital costs as shown in Table 1.[74]

In 2007-2008, Refinery K decided to install ESPs, and they reported that the project cost was $43.8 million as shown in Table 1. Fifty five percent of that cost, or approximately $36.8 million, was attributed to installation costs without identifying specific details. Refinery K indicated that they selected to install ESPs to save costs. The reported capital costs for the ESPs were about one halve of the estimated costs for the WGS project.[75]

[74] An Evaluation of the Feasibility and Costs for Control of PM-10 Emissions at South Coast Refinery FCCUs (SCAQMD Proposed Rule 1105.1), NEXANT, Inc. for The Western States Petroleum Association, May 2003.

[75] E-mail communication from Refinery K to SCAQMD on February 10, 2010 and at March 18, 2010 site visit.

TABLE 1
Cost Estimates and Reported Capital Costs (Million Dollars)

	Cost Estimates for WGS	Reported Costs for ESPs	Difference
Equipment Cost	68	7.0	10 times lower (68/7 = 9.7)
Demolition	0.5	36.8	3 times higher (36.8/10.7 = 3.4)
Electrical Substation	0.8		
Paving/Pile Driving	0.5		
Modification to wastewater treatment & SRU/TGs	1.1	Not needed	
NOx control tie-in	0.3		
Extended downtime	7.5		
Total Capital Costs	**78.7**	**43.8**	**2 times lower** (78.7/43.8 = 1.8)

Refinery Y

During the development of Rule 1105.1 in 2003, Refinery Y indicated that they would install a dry ESP to comply with the proposed rule. Refinery Y developed a cost estimate for the project including a Hamon Research Cottrell's ESP. There were also extensive costs for ducting/piping and site modification since Refinery Y planned to install the ESP far away from the FCCU. WSPA's consultant reviewed Refinery Y's cost estimates and added costs for additional ducting and supports, insulation, asbestos abatement, SCR/stack relocation, new foundations and paving, electrical instrumentation and controls, piping relocation, and demolition. The estimated capital costs were \$48.9 million.[76] In 2007-2008, Refinery Y installed ESPs. Refinery Y reported that the total cost of the project was \$340 million. The estimated costs and reported costs are presented in Table 2.[77]

The substantial differences in the reported costs and the cost estimates are shown in Table 2. The reported equipment costs are 35% higher than the estimated costs. The site preparation costs are almost the same as estimated. There are substantial differences in the installation costs including ducting, supports, electrical substation modification, and engineering/management costs. The reported installation costs are 30 times higher than estimated, and the overall reported costs are 7 times higher than estimated.

[76] An Evaluation of the Feasibility and Costs for Control of PM-10 Emissions at South Coast Refinery FCCUs (SCAQMD Proposed Rule 1105.1), NEXANT, Inc. for The Western States Petroleum Association, May 2003

[77] E-mail communication from Refinery Y to SCAQMD on July 7, 2010. Refinery Y reported the following: equipment/materials (\$54 million), installation/demolition (\$5 million), civil (\$25 million), mechanical - steel/piping/ESP assembly (\$109 million), electrical and instrumentation (\$17 million), support crafts - cranes, scaffolding etc. (\$60 million), and engineering and construction management (\$75 million).

TABLE 2
Cost Estimates and Reported Capital Costs (Million Dollars)

	Cost Estimates	**Reported Costs**	**Difference**
Equipment Cost	40	54	35% higher (54/40=1.35)
Ducting/Support/ Insulation	4.8	186 [78]	30 times higher (186/5.55=30.5)
Induced fans	0.35		
Electrical Substation	0.4		
Demolition	2	25	Almost the same (25/23=1.1)
Asbestos Removal	0.15		
Contaminated Soil Disposal	0.1		
Foundations/Paving	0.75		
Site Upgrade	20		
Engineering/Management	Included above	75	---
SCR relocation	0.35	Not needed	---
Total Capital Costs	**48.9**	**340**	**7 times higher** (340/48.9 = 6.95)

Refinery # M

Refinery M installed a new ESP in 1993. Total capital costs were $13.6 million.[79] At a 3% inflation rate, the capital costs would be approximately $23 million in current dollars.[80]

TABLE 3
Reported Capital Costs (Million Dollars)

	Reported Costs
Equipment Costs	5.83
Installation Costs	7.80
Total Capital Costs	**13.63 (about 23 today)**

[78] The actual costs of $186 million = 109+60+17

[79] Fax communication from Refinery M to SCAQMD on March 9, 1995: Materials = $5,837,000; Engineering = $1,946,000; Construction labor = $4,610,000; Miscellaneous = $1,240,000; and Total Costs = $13.6 million.

[80] The Chemical Engineering Plant Cost Annual Index and the Marshall & Swift Cost Index show that there was a 3% inflation rate from 1993 to 2005. With a 3% inflation rate, the costs in current dollars would be (14) (1.03) exp (2010-1993) = (14) (1.03) exp (17) = (14) (1.65) = $23 million. In a recent e-mail communication with the SCAQMD on February 19, 2010, Refinery M used a 7% inflation rate to estimate the costs at (14)(1.07) exp(2010-1993) = $45 million and claimed the costs would be $60 million with extra compliance flexibility.

Refinery W

During the development of Rule 1105.1 in 2003, Refinery W indicated that they would install a dry ESP to comply with the proposed rule. Refinery W and WSPA's consultant developed a cost estimate for the project including a large ESP and extensive costs for ducting, relocation of a roadway, underground sewers and drains, piling, disposal of contaminated soil, new electrical substation, SCR, engineering/management, and extended shutdown. The estimated capital costs were \$38 million.[81] In 2007-2008, Refinery W installed 3 ESPs and reported that the total cost of the project was \$121.3 million.[82] The estimated costs and reported as actual costs by Refinery W are presented in Table 4.

The reported equipment costs and engineering costs are about 2 times higher than estimated. However, there are substantial differences in the construction and installation costs including ducting, supports, electrical substation modification etc., which cause the reported installation costs to rise up to 9 times higher than estimated, and the overall reported costs 4 times higher than estimated.

TABLE 4
Cost Estimates and Reported Capital Costs (Million Dollars)

	Cost Estimates	**Reported Costs**	**Difference**
Equipment Cost	8 – 12	15	2 times higher (15/8=1.9)
SCR	10	Not specified	---
Site preparation and Construction	9.1[83]	95.4	9 times higher (95.4/10.5=9.1)
Electrical Substation	1.4		
Engineering/Management	4.8	10.9	2 times higher (10.9/4.8=2.3)
Extended turnaround	2.7	Not needed	
Total Capital Costs	**38.0**	**121.3**	**4 times higher** (121/33=3.67)

[81] An Evaluation of the Feasibility and Costs for Control of PM-10 Emissions at South Coast Refinery FCCUs (SCAQMD Proposed Rule 1105.1), NEXANT, Inc. for The Western States Petroleum Association, May 2003. NEXANT estimated ESP costs from \$8 - \$12 million. Site preparation costs included relocating a refinery road (\$400,000), relocating sewers/drains/piping (\$650,000), disposal of contaminated soil (\$100,000), piling (\$350,000), and 35% contingency (\$7.6 million). New electrical substation was added (\$800,000) and existing distribution system was modified (\$600,000). Engineering and management costs were estimated (\$800,000) and owners costs (\$4 million)

[82] E-mail communication from Refinery W to SCAQMD on March 30, 2010. Refinery W reported the following costs: equipment/materials (\$15 million), construction (\$62.6 million), material (\$21.3 million), incentive (\$1.2 million), pre-capital expense (\$2.9 million) + demolition (\$2.9 million), engineering (\$10.9 million) and owner's costs (\$4.5 million)

[83] This footnote is to estimate the estimations in Table 4. Site preparation = 0.4+ 0.65+0.35+0.10+ 7.6 = 9.1. Electrical substation = 0.8+0.6 = 1.4. Engineering Management = 0.8+4.0 = 4.8. Construction costs = 62.6+21.3+1.2+4.5+2.9+2.9=95.4. In Table 5, Construction costs = 24.4+ 7.9+ 1.0 = 33.3. In Table 6,

Refinery X

In 2003, Refinery X planned to install 2 ESPs and 2 SCRs to meet R.1105.1 limits at the costs of $43 million.[84] However, in 2007-2008, Refinery X decided to install a WGS at the costs of $58.9 million.[85] The estimated and reported costs are provided in Table 5.

TABLE 5
Cost Estimates and Reported Capital Costs (Million Dollars)

	Cost Estimates	Reported Costs	Difference
Equipment Cost	28	18.9	35% higher (18.9/14 = 1.35)
CO boiler or SCR	10	Not included	
Ducting/Support & Insulation	3.1	33.3	6 times higher (33.3/5.3 = 6.3)
Electrical Substation	0.8		
Asbestos Removal	0.1		
Contaminated Soil Disposal	0.1		
Owner's Costs	1.2	6.7	6 times higher (6.7/1.2 = 5.6)
Total Capital Costs	**43.3**	**58.9**	**2 times higher** (58.9/33.3 = 1.8)

Comparing the two estimates, the costs for the WGS/WESP ($18.9 million including a $5 million cost for a fin fan cooler) is about the same as a single, large ESP ($14 million).
The major differences in the 2010 reported as actual costs and the 2003 estimates are in the installation and owner's costs. The reported installation costs including construction, demolition, and engineering and the reported owner's costs are approximately 6 times higher than 2003 estimates. The overall 2010 reported costs are approximately 2 times higher than the 2003 estimates (not including the SCRs), and three times higher than the ESP costs.

Refinery L

During the development of Rule 1105.1, Refinery L indicated that they would install ESPs to meet the requirements of Rule 1105.1. Refinery L hired a consultant (Jacobs Engineering) to develop a feasibility and cost estimate to comply with the proposed Rule 1105.1 limit for both ESPs and WGS. Jacobs Engineering recommended Refinery L to select dry ESPs, and they designed the ESPs with 25% larger collecting area. In their estimates, they assumed the costs of project engineering and

[84] An Evaluation of the Feasibility and Costs for Control of PM-10 Emissions at South Coast Refinery FCCUs (SCAQMD Proposed Rule 1105.1), NEXANT, Inc. for The Western States Petroleum Association, May 2003. The costs were estimated for two new ESPs in parallel, 200% capacity total, with two new SCRs.

[85] E-mail from Refinery X to SCAQMD on March 19, 2020. Refinery X reported the following: equipment/materials ($18.9 million), construction ($24.4 million), engineering ($7.9 million), demolition ($1 million), and owner's costs ($6.7 million).

services averaged 18.7% of the total capital costs. The total estimated costs are $57 million dollars.[86] The cost estimates are presented in Table 12-3-6.

In 2007-2008, Refinery L installed ESPs. The costs of $102 million dollars reported as the actual costs for this project provided by Refinery L are presented in Table 6.[87]

TABLE 6
Cost Estimates and Reported Capital Costs (Million Dollars)

	Cost Estimates	Reported Costs	Difference
Equipment Cost	10	17.547	2 times higher (17.5/10 = 1.8)
Project Management	10.66	6.23	2 times higher (15.5/10.66 = 1.5)
Engineering		9.27	
Construction Indirects	36.34	15.60	2 times higher (69.1/36.3 = 1.9)
Construction Directs		45.202	
Start –Up		2.269	
Demolition		0.378	
Other Costs		5.635	
Total Capital Costs	**57**	**102.135**	**2 times higher** (102/57 = 1.8)

The differences in the 2010 reported costs and the 2003 estimates are shown in Table 6. The reported equipment costs, installation costs, and capital costs are consistently about 2 times higher than the 2003 estimates.

Summary & Staff's Analysis

A comparison of the costs reported by the refineries as actual costs, and the estimated costs during the rule development process are provided in Table 7 and staff's analysis is as follows.

Equipment Costs

The reported equipment costs are not much different than estimated. The reported costs are about 35% higher for Refinery Y and Refinery X, 2 times higher for Refinery W and L, and 10% lower for Refinery K. The differences are due to inflation (about 3% between 2003 and 2010), extra capacity for redundancy built in the design, and the price surge of steel in 2007-2008 time frames.

86 An Evaluation of the Feasibility and Costs for Control of PM-10 Emissions at South Coast Refinery FCCUs (SCAQMD Proposed Rule 1105.1), NEXANT, Inc. for The Western States Petroleum Association, May 2003. The costs were estimated for a large ESP with 25% more capacity.

87 E-mails communication from Refinery L to SCAQMD on January 27, 2010 and February 08, 2010 provide detailed information in cost breakdown. Staff combined the costs provided into these following categories a) Project Management includes contractor costs ($5.760 million) and owner costs ($0.471 million); b) Engineering costs include contractor costs ($9.264 million) and owner costs ($0.01 million); c) Construction Indirect Owner Costs of $1.050 million is for temporary facilities/services/utilities. Construction Indirect Contractor Costs of $14.549 million includes construction management ($6.349 million), equipment not provided by sub-contractors ($4.303 million), and temporary facilities/services/utilities ($3.898 million); d) ISBL Construction Directs of $62.719 million include equipment ($17.547 million); civil/site ($0.419 million), concrete ($0.901 million), steel ($6.331 million), piping ($3.915 million), process air ($2.479 million), electrical ($19.120 million), process control ($5.719 million), paint/insulation/fireproofing ($6.317 million)

WGS/WESP versus ESPs

Refinery X planned to use ESPs but installed a WGS. Refinery K planned to use WGS but installed ESPs. Refinery X data shows that there is no difference in the equipment costs of a WGS/WESP/fin fan cooler system versus two ESPs to meet the requirement of Rule 1105.1 and also to mitigate the plume if necessary. Refinery K data shows that the equipment costs for ESPs are 10 times lower than the costs for a WGS system. It seems that Refinery K over-estimated the costs of their WGS system by building a larger unit than necessary, adding a new wastewater treatment to handling the waste that could be handled by the purge treatment system, and using a gas-to-gas reheat exchanger instead of a fin-fan cooler.

TABLE 7
Cost Estimates and Reported Costs (Million Dollars)

	Ref M	**Ref K**	**Ref Y**	**Ref W**	**Ref X**	**Ref L**	**Total**
Estimated Capital Costs	---	78.7	48.9	38.0	43.3	57.0	**266.0**
Reported Equipment Costs	*7.0*	*7.0*	*54.0*	*15*	*18.9*	*17.5*	***119.4***
Reported Capital Costs [88]	23.0	43.8	340.0	121.3	58.9	102	**666.0**
Reported Capital Costs / Estimated Capital Costs	---	0.6	7.0	4.0	1.8	1.8	**2.5 (average)**
Reported Capital Costs (2010) / Reported Equipment Cost (2010)	*2.0*	*6.3*	*6.2*	*8.1*	*3.1*	*5.8*	***5.6 (average)***

Installation Costs

There are substantial differences in reported installation costs versus estimated installation costs: 2 times higher for Refinery L, 3 times higher for Refinery K, 6 times higher for Refinery X, 9 times higher for Refinery W, and 30 times higher for Refinery Y. Note that site preparation did not cause this substantial difference in Refinery Y case. The vast differences originate from ducting, supports, electrical substation modification, engineering, management, and labor costs. Refinery L provided the following explanations which may apply to other refineries as well: [89]

— Materials Costs. The reported cost includes a) steel, concrete, site excavation, painting, fireproofing for foundation and buildings, b) insulation for ducting/piping, c) substantial amount for wiring/conduit for substation and power distribution, and d) substantial amount for instrument/controls. These categories are underestimated in 2003, especially the costs for steel, electrical wiring, and instrument/controls. Costs of steel increased by at least 2 in 2008 time frame.

---

[88] WSPA's estimates are in the neighborhood of $750 million based on a wrong estimate for Refinery M at $60 million using 7% inflation rate and $70 million AFE costs for Refinery X. That is, 43.8 + 340 + 60 + 121.3 + 70 + 102.1 = $742 million. Refinery X actual installation costs are only $58.9 million.

[89] E-mail communication from Refinery L to SCAQMD on May 27, 2010.

— Inflation. Construction was completed in 2008, and during 2008, there was a period of hyper inflation in heavy industrial construction equipment and labor costs.

— Union Labor Costs. Due to the volume of construction activity in late 2007 to early 2008, union construction resources were used while the estimate in 2003 was based on non-union construction labor. There is an overall cost differential of over 30% between non-union and union labor forces.

— Compressed Construction Schedule. To meet a FCCU turnaround date, the construction schedule was accelerated. It is important to note that the litigation filed by WSPA immediately after Rule 1105.1 was adopted in November 2003, and subsequent appeal of the original judgment, contributed significantly in further compressing the construction schedule. All five refineries delayed the construction of the control equipment until WSPA finally lost the law suit in late 2006. This scheduling constraints in conjunction with the limited number of control equipment vendors/manufacturers and contractors that the refineries selected to contract with for this project contributed substantially to the price escalation.

— Redundancy. In order for the vendor to guarantee R1105.1 level of particulate capture, the vendor had to add extra capacity to the ESP, larger than estimated in 2003.

Capital Costs

Overall, the reported capital costs are higher than estimated: 2 times higher for Refinery K, X and L, 4 times higher for Refinery W, and 7 times higher for Refinery Y. On average, the reported capital costs are 2.5 times higher than estimated.

Refinery Y and W are the two outliers from the average with reported costs about 2-3 times higher than other refineries:

— Refinery Y's total gas flow rate (540,111 acfm reported in 2003) is about 25% higher than Refinery L's (436,035 acfm total gas flow)[90] however the equipment costs of Refinery Y ($54 million) is about 3 times higher than that of Refinery L ($17.5 million), and their reported capital costs ($340 million) is also about 3 times higher than Refinery L's ($102 million).

— Refinery W's total gas flow rate (218,628 acfm reported in 2003) is about the same as Refinery K's (212,514 acfm total gas flow) however the reported equipment costs of Refinery W ($15 million) is about 2 times higher than Refinery K's ($7 million), and their capital costs ($121 million) is about 3 times higher than Refinery K's ($43.8 million).

— Refinery Y and #4 did seem to add extraordinary capacity to their ESPs and upgrade other systems at their sites along with installing the ESPs.

[90] SP Environmental Report, August 2003.

Comparison between Costs Reported As Actual Capital Costs and Equipment Costs

The costs reported by the refineries as actual capital costs are 2 times higher than the equipment costs for Refinery M, 3 times higher for Refinery X, 6 times higher for Refinery K, Y, and L, and 8 times higher for Refinery W. It is interesting to note that there are two distinct groups: Refinery M and X, with a ratio between 2 and 3, and Refinery K, Y, W and L with a ratio between 6 and 8. It appears that Refinery K, Y, W and L may have spent additional money on upgrading other existing systems (ducting, supports, electrical substation modification, NOx/SOx CEMS) and used more in engineering and management compared to Refinery X and L. However, on average, the reported capital costs are about 5-6 times higher than the equipment costs. **It is important to note that the consultants hired to assist staff with the BARCT and cost analysis of the proposed amended Regulation XX (SOx RECLAIM), namely ETS, Inc., AEC and NEC, have used a ratio of 5x in their cost analyses for refineries.**

Appendix F – U.S. Refineries Operable Capacities

(Reference: U.S. Energy Information Administration)

RANK	CORPORATION	COMPANY	STATE	SITE	Barrels per Calendar Day
1	EXXON MOBIL CORP	EXXONMOBIL REFINING & SUPPLY CO	Texas	BAYTOWN	560,640
2	EXXON MOBIL CORP	EXXONMOBIL REFINING & SUPPLY CO	Louisiana	BATON ROUGE	504,500
3	BP PLC	BP PRODUCTS NORTH AMERICA INC	Texas	TEXAS CITY	437,080
4	MARATHON OIL CORP	MARATHON PETROLEUM CO LLC	Louisiana	GARYVILLE	436,000
5	PDV AMERICA INC	CITGO PETROLEUM CORP	Louisiana	LAKE CHARLES	429,500
6	BP PLC	BP PRODUCTS NORTH AMERICA INC	Indiana	WHITING	405,000
7	WRB REFINING LLC	WRB REFINING LLC	Illinois	WOOD RIVER	362,000
8	EXXON MOBIL CORP	EXXONMOBIL REFINING & SUPPLY CO	Texas	BEAUMONT	344,500
9	SUNOCO INC	SUNOCO INC (R&M)	Pennsylvania	PHILADELPHIA	335,000
10	CHEVRON CORP	CHEVRON USA INC	Mississippi	PASCAGOULA	330,000
11	DEER PARK REFINING LTD PTNRSHP	DEER PARK REFINING LTD PARTNERSHIP	Texas	DEER PARK	327,000
12	KOCH INDUSTRIES INC	Flint Hills Resources LP	Texas	CORPUS CHRISTI	290,078
13	VALERO ENERGY CORP	PREMCOR REFINING GROUP INC	Texas	PORT ARTHUR	287,000
14	MOTIVA ENTERPRISES LLC	Motiva Enterprises LLC	Texas	PORT ARTHUR	285,000
15	ACCESS INDUSTRIES	HOUSTON REFINING LP	Texas	HOUSTON	280,700
16	KOCH INDUSTRIES INC	Flint Hills Resources LP	Minnesota	SAINT PAUL	280,500
17	CHEVRON CORP	CHEVRON USA INC	California	EL SEGUNDO	265,500
18	BP PLC	BP West Coast Products LLC	California	LOS ANGELES	265,000
19	CONOCOPHILLIPS	CONOCOPHILLIPS COMPANY	Louisiana	BELLE CHASSE	247,000
20	CONOCOPHILLIPS	CONOCOPHILLIPS COMPANY	Texas	SWEENY	247,000
21	CHEVRON CORP	CHEVRON USA INC	California	RICHMOND	245,271
22	CONOCOPHILLIPS	CONOCOPHILLIPS COMPANY	Louisiana	WESTLAKE	239,400
23	EXXON MOBIL CORP	EXXONMOBIL REFINING & SUPPLY CO	Illinois	JOLIET	238,600
24	CONOCOPHILLIPS	CONOCOPHILLIPS COMPANY	New Jersey	LINDEN	238,000
25	MOTIVA ENTERPRISES LLC	Motiva Enterprises LLC	Louisiana	CONVENT	235,000
26	MOTIVA ENTERPRISES LLC	Motiva Enterprises LLC	Louisiana	NORCO	234,700
27	TOTAL SA	TOTAL PETROCHEMICALS INC	Texas	PORT ARTHUR	232,000
28	BP PLC	BP West Coast Products LLC	Washington	FERNDALE	225,000
29	KOCH INDUSTRIES INC	FLINT HILLS RESOURCES ALASKA LLC	Alaska	NORTH POLE	219,500
30	VALERO ENERGY CORP	VALERO REFINING CO TEXAS LP	Texas	TEXAS CITY	214,000
31	MARATHON OIL CORP	MARATHON PETROLEUM CO LLC	Kentucky	CATLETTSBURG	212,000
32	MARATHON OIL CORP	MARATHON PETROLEUM CO LLC	Illinois	ROBINSON	206,000
33	CONOCOPHILLIPS	CONOCOPHILLIPS COMPANY	Oklahoma	PONCA CITY	198,400
34	CHALMETTE REFINING LLC	Chalmette Refining LLC	Louisiana	CHALMETTE	192,500
35	VALERO ENERGY CORP	VALERO REFINING NEW ORLEANS LLC	Louisiana	NORCO	185,003

36	CONOCOPHILLIPS	CONOCOPHILLIPS COMPANY	Pennsylvania	TRAINER	185,000
37	VALERO ENERGY CORP	PREMCOR REFINING GROUP INC	Tennessee	MEMPHIS	180,000
38	SUNOCO INC	SUNOCO INC	Pennsylvania	MARCUS HOOK	178,000
39	VALERO ENERGY CORP	VALERO ENERGY CORPORATION	Texas	SUNRAY	171,000
40	PDV AMERICA INC	PDV Midwest Refining LLC	Illinois	LEMONT	167,000
41	TESORO CORP	TESORO REFINING & MARKETING CO	California	MARTINEZ	166,000
42	PDV AMERICA INC	CITGO REFINING & CHEMICAL INC	Texas	CORPUS CHRISTI	163,000
43	SUNOCO INC	SUNOCO INC	Ohio	TOLEDO	160,000
44	VALERO ENERGY CORP	VALERO REFINING CO NEW JERSEY	New Jersey	PAULSBORO	160,000
45	ROYAL DUTCH/SHELL GROUP	Shell Oil Products US	California	MARTINEZ	156,400
46	HUSKY ENERGY INC	LIMA REFINING COMPANY	Ohio	LIMA	150,000
47	EXXON MOBIL CORP	EXXONMOBIL REFINING & SUPPLY CO	California	TORRANCE	149,500
48	WRB REFINING LLC	WRB REFINING LLC	Texas	BORGER	146,000
49	ROYAL DUTCH/SHELL GROUP	Shell Oil Products US	Washington	ANACORTES	145,000
50	VALERO ENERGY CORP	VALERO REFINING CO CALIFORNIA	California	BENICIA	144,000
51	VALERO ENERGY CORP	VALERO REFINING CO TEXAS LP	Texas	CORPUS CHRISTI	142,000
52	CONOCOPHILLIPS	CONOCOPHILLIPS COMPANY	California	WILMINGTON	139,000
53	FRONTIER OIL REFINING & MKTG	FRONTIER EL DORADO REFINING CO	Kansas	EL DORADO	130,000
54	BP HUSKY REFINING LLC	BP-HUSKY REFINING LLC	Ohio	TOLEDO	125,700
55	WESTERN REFINING INC.	WESTERN REFINING COMPANY LP	Texas	EL PASO	122,000
56	CONOCOPHILLIPS	CONOCOPHILLIPS COMPANY	California	RODEO	120,200
57	MURPHY OIL CORP	MURPHY OIL USA INC	Louisiana	MERAUX	120,000
58	TESORO CORP	Tesoro West Coast	Washington	ANACORTES	120,000
59	CVR ENERGY INC	COFFEYVILLE RESOURCES RFG & MKTG LLC	Kansas	COFFEYVILLE	115,700
60	MARATHON OIL CORP	MARATHON PETROLEUM CO LLC	Michigan	DETROIT	106,000
61	HOLLY CORP	NAVAJO REFINING CO	New Mexico	ARTESIA	105,000
62	CONOCOPHILLIPS	CONOCOPHILLIPS COMPANY	Washington	FERNDALE	100,000
63	PETROLEO BRASILEIRO SA	PASADENA REFINING SYSTEMS INC	Texas	PASADENA	100,000
64	TESORO CORP	TESORO REFINING & MARKETING CO	California	WILMINGTON	96,860
65	TESORO CORP	TESORO HAWAII CORP	Hawaii	EWA BEACH	93,500
66	VALERO ENERGY CORP	VALERO ENERGY CORPORATION	Texas	THREE RIVERS	93,000
67	VALERO ENERGY CORP	VALERO REFINING CO OKLAHOMA	Oklahoma	ARDMORE	87,400
68	CHS INC	NCRA	Kansas	MCPHERSON	85,500
69	HOLLY CORP	HOLLY REFINING & MARKETING CO	Oklahoma	TULSA WEST	85,000
70	VALERO ENERGY CORP	VALERO REFINING CO TEXAS LP	Texas	HOUSTON	83,000
71	VALERO ENERGY CORP	VALERO REFINING CO CALIFORNIA	California	WILMINGTON REFINERY	80,887
72	ALON ISRAEL OIL COMPANY LTD	ALON REFINING KROTZ SPRINGS INC	Louisiana	KROTZ SPRINGS	80,000
73	CHEVRON CORP	CHEVRON USA INC	New Jersey	PERTH AMBOY	80,000
74	ROYAL DUTCH/SHELL GROUP	SHELL CHEMICAL LP	Alabama	SARALAND	80,000
75	TRANSWORLD OIL USA INC	CALCASIEU REFINING CO	Louisiana	LAKE CHARLES	78,000

76	MARATHON OIL CORP	MARATHON PETROLEUM CO LLC	Ohio	CANTON	78,000
77	MARATHON OIL CORP	MARATHON PETROLEUM CO LLC	Texas	TEXAS CITY	76,000
78	ERGON INC	LION OIL CO	Arkansas	EL DORADO	75,000
79	MARATHON OIL CORP	MARATHON PETROLEUM CO LLC	Minnesota	SAINT PAUL	74,000
80	SINCLAIR OIL CORP	SINCLAIR WYOMING REFINING CO	Wyoming	SINCLAIR	74,000
81	TESORO CORP	TESORO ALASKA PETROLEUM CO	Alaska	KENAI	72,000
82	HOLLY CORP	HOLLY REFINING & MARKETING CO	Oklahoma	TULSA EAST	70,300
83	GARY WILLIAMS CO	WYNNEWOOD REFINING CO	Oklahoma	WYNNEWOOD	70,000
84	ALON ISRAEL OIL COMPANY LTD	ALON USA ENERGY INC	Texas	BIG SPRING	67,000
85	SUNCOR ENERGY INC	SUNCOR ENERGY (USA) INC	Colorado	COMMERCE CITY WEST	67,000
86	WESTERN REFINING INC.	WESTERN REFINING YORKTOWN INC	Virginia	YORKTOWN	66,300
87	FLYING J INC	BIG WEST OF CALIFORNIA	California	BAKERSFIELD	66,000
88	UNITED REFINING INC	UNITED REFINING CO	Pennsylvania	WARREN	65,000
89	EXXON MOBIL CORP	EXXONMOBIL REFINING & SUPPLY CO	Montana	BILLINGS	60,000
90	CHS INC	Cenex Harvest States Coop	Montana	LAUREL	59,600
91	CONOCOPHILLIPS	CONOCOPHILLIPS COMPANY	Montana	BILLINGS	58,000
92	DELEK GROUP LTD	DELEK REFINING LTD	Texas	TYLER	58,000
93	TESORO CORP	Tesoro West Coast	North Dakota	MANDAN	58,000
94	TESORO CORP	Tesoro West Coast	Utah	SALT LAKE CITY	58,000
95	CALUMET LUBRICANTS CO	CALUMET SHREVEPORT LLC	Louisiana	SHREVEPORT	57,000
96	PLACID OIL CO	PLACID REFINING CO	Louisiana	PORT ALLEN	57,000
97	ARCTIC SLOPE REGIONAL CORP	PETRO STAR INC	Alaska	VALDEZ	55,000
98	ROYAL DUTCH/SHELL GROUP	SHELL CHEMICAL LP	Louisiana	SAINT ROSE	55,000
99	CHEVRON CORP	CHEVRON USA INC	Hawaii	HONOLULU	54,000
100	ALON ISRAEL OIL COMPANY LTD	PARAMOUNT PETROLEUM CORPORATION	California	PARAMOUNT	53,000
101	FRONTIER OIL REFINING & MKTG	FRONTIER REFINING INC	Wyoming	CHEYENNE	47,000
102	CHEVRON CORP	CHEVRON USA INC	Utah	SALT LAKE CITY	45,000
103	COMPAGNIE NATIONALE AÂ PORTEFEUILLE	US OIL & REFINING CO	Washington	TACOMA	37,850
104	HUNT CONSLD INC	HUNT REFINING CO	Alabama	TUSCALOOSA	36,000
105	SUNCOR ENERGY INC	SUNCOR ENERGY (USA) INC	Colorado	COMMERCE CITY EAST	35,000
106	MURPHY OIL CORP	MURPHY OIL USA INC	Wisconsin	SUPERIOR	34,300
107	NUSTAR ENERGY LP	NUSTAR ASPHALT REFINING LLC	New Jersey	PAULSBORO	32,000
108	ALON ISRAEL OIL COMPANY LTD	EDGINGTON OIL CO INC	California	LONG BEACH	31,500
109	FLYING J INC	BIG WEST OIL CO	Utah	NORTH SALT LAKE	29,400
110	NUSTAR ENERGY LP	NUSTAR ASPHALT REFINING LLC	Georgia	SAVANNAH	28,000
111	COUNTRYMARK COOP INC	COUNTRYMARK COOPERATIVE INC	Indiana	MOUNT VERNON	26,500
112	KERN OIL & REFINING CO	KERN OIL & REFINING CO	California	BAKERSFIELD	26,000
113	HOLLY CORP	HOLLY REFINING & MARKETING CO	Utah	WOODS CROSS	25,050
114	SINCLAIR OIL CORP	LITTLE AMERICA REFINING CO	Wyoming	EVANSVILLE	24,500

115	ERGON INC	ERGON REFINING INC	Mississippi	VICKSBURG	23,000
116	WESTERN REFINING INC.	WESTERN REFINING SOUTHWEST INC	New Mexico	GALLUP	20,800
117	ERGON INC	ERGON WEST VIRGINIA INC	West Virginia	NEWELL	20,000
118	ARCTIC SLOPE REGIONAL CORP	PETRO STAR INC	Alaska	NORTH POLE	19,700
119	WESTERN REFINING INC.	WESTERN REFINING SOUTHWEST INC	New Mexico	BLOOMFIELD	16,800
120	CONOCOPHILLIPS	CONOCOPHILLIPS ALASKA INC	Alaska	PRUDHOE BAY	15,000
121	SAN JOAQUIN REFINING CO INC	SAN JOAQUIN REFINING CO INC	California	BAKERSFIELD	15,000
122	AGE REFINING & MARKETING INC	AGE REFINING INC	Texas	SAN ANTONIO	14,021
123	WYOMING REFINING CO	WYOMING REFINING CO	Wyoming	NEW CASTLE	14,000
124	CALUMET LUBRICANTS CO	CALUMET LUBRICANTS CO LP	Louisiana	COTTON VALLEY	13,020
125	BP PLC	BP EXPLORATION ALASKA INC	Alaska	PRUDHOE BAY	12,780
126	VENTURA REFINING AND TRANSMISSION LLC	VENTURA REFINING & TRANSMISSION LLC	Oklahoma	THOMAS	12,000
127	HUNT CONSLD INC	HUNT SOUTHLAND REFINING CO	Mississippi	SANDERSVILLE	11,000
128	SILVER EAGLE REFINING INC	Silver Eagle Refining	Utah	WOODS CROSS	10,250
129	AMERICAN REFINING GROUP INC	AMERICAN REFINING GROUP INC	Pennsylvania	BRADFORD	10,000
130	CONNACHER OIL & GAS LTD	MONTANA REFINING CO	Montana	GREAT FALLS	10,000
131	GREKA ENERGY	Greka Energy	California	SANTA MARIA	9,500
132	WORLD OIL CO	LUNDAY THAGARD CO	California	SOUTH GATE	8,500
133	CALUMET LUBRICANTS CO	CALUMET LUBRICANTS CO LP	Louisiana	PRINCETON	8,300
134	MARTIN RESOURCE MANAGEMENT GRP	MARTIN MIDSTREAM PARTNERS LP	Arkansas	SMACKOVER	7,500
135	VALERO ENERGY CORP	VALERO REFINING CO CALIFORNIA	California	WILMINGTON ASPHALT PLANT	6,300
136	MIDSOUTH ENERGY LLC	SOMERSET ENERGY REFINING LLC	Kentucky	SOMERSET	5,500
137	GOODWAY REFINING LLC	GOODWAY REFINING LLC	Alabama	ATMORE	4,100
138	GARCO ENERGY LLC	GARCO ENERGY LLC	Wyoming	DOUGLAS	3,600
139	SILVER EAGLE REFINING INC	Silver Eagle Refining	Wyoming	EVANSTON	3,000
140	OIL HOLDING INC	TENBY INC	California	OXNARD	2,800
141	FORELAND REFINING CORP	FORELAND REFINING CORP	Nevada	ELY	2,000

*Only Refineries with Atmospheric Crude Oil Distillation Capacity.
Source: Refinery Capacity Data by individual refinery as of January 1, 2010

Appendix G – FCCU Capacity of California Refineries

Reference: U.S. Energy Information Administration "Capacity of Operable Petroleum Refineries by State as of January 1, 2010"

CORPORATION	COMPANY_NAME	SITE	PRODUCT	QUANTITY (Barrels Per Calendar Day)
BP PLC	BP WEST COAST PRODUCTS LLC	LOS ANGELES	CAT CRACKING: FRESH FEED	101,500
EXXON MOBIL CORP	EXXONMOBIL REFINING & SUPPLY CO	TORRANCE	CAT CRACKING: FRESH FEED	83,500
CHEVRON CORP	CHEVRON USA INC	RICHMOND	CAT CRACKING: FRESH FEED	80,000
VALERO ENERGY CORP	VALERO REFINING CO CALIFORNIA	BENICIA	CAT CRACKING: FRESH FEED	72,000
TESORO CORP	TESORO REFINING & MARKETING CO	MARTINEZ	CAT CRACKING: FRESH FEED	68,000
CHEVRON CORP	CHEVRON USA INC	EL SEGUNDO	CAT CRACKING: FRESH FEED	66,500
ROYAL DUTCH/SHELL GROUP	SHELL OIL PRODUCTS US	MARTINEZ	CAT CRACKING: FRESH FEED	61,800
VALERO ENERGY CORP	VALERO REFINING CO CALIFORNIA	WILMINGTON REFINERY	CAT CRACKING: FRESH FEED	52,200
CONOCOPHILLIPS	CONOCOPHILLIPS COMPANY	WILMINGTON	CAT CRACKING: FRESH FEED	48,700
TESORO CORP	TESORO REFINING & MARKETING CO	WILMINGTON	CAT CRACKING: FRESH FEED	31,958

Appendix H – List of World's Largest Corporations

Reference: Fortune Global 500, Fortune Magazine, July 26, 2010

Rank 2009	Rank 2008	Corporation	Country	Revenues ($ millions)	% change from 2008
1	3	Wal-Mart Stores	U.S.	408,214.0	+0.6
2	1	Royal Dutch Shell	Netherlands	285,129.0	-39.5
3	2	ExxonMobil	U.S.	284,650.0	-35.7
4	4	BP	Britain	246,138.0	-32.9
5	1	Toyota Motor	Japan	204,106.1	-0.1
6	11	Japan Post Holdings	Japan	202,196.1	+1.8
7	9	Sinopec	China	187,517.7	-9.8
8	15	Stategrid	China	184,495.8	+12.4
9	73	AXA	France	175,257.4	+118.4
10	13	China National Petroleum	China	165,496.5	-8.6
11	5	Chevron	U.S.	163,527.0	-37.9
12	8	Ing Group	Netherlands	163,203.8	-28.0
13	12	General Electric	U.S.	156,779.0	-14.4
14	6	Total	France	155,887.1	-33.6
15	37	Bank of America Corp.	U.S.	150,450.0	+33.0
16	14	Volkswagen	Germany	146,204.7	-12.2
17	7	ConocoPhillips	U.S.	139,515.0	-39.5
18	24	BNP Paribas	France	130,708.1	-4.0
19	47	Assicurazioni Generali	Italy	126,012.5	+22.2
20	20	Allianz	Germany	125,999.0	-11.5

The top 20 corporations are listed in the table above. The table above contains information listed in the list of "Fortune Global 500", Fortune magazine, dated July 26, 2010. As explained in the Fortune magazine, Fortune Global 500 ranks 500 corporations that have the largest revenues in the world, in descending order, according to their total revenues for their respective fiscal years ended on or before March 31, 2010. All companies on the list of Fortune Global 500 must publish financial data and report part or all of their figures to a government agency. Figures in the lists are as reported, and comparisons are with the prior year's figures as originally reported for that year. The list shows that general global economy is down for almost all corporations in 2008-2009. However, several of the corporations such as ExxonMobil, BP, Chevron, and ConocoPhillips still remain as the top 20 richest corporations in the world.

Appendix I – Projected 2019 Emissions & Growth Factors

(Authors: Susan Yan, Kathy Hsiao, and Ali Ghasemi)

2019 RECLAIM SOx Baseline Emissions and Reductions Calculation

The AQMD's Annual Emission Reports (AER) team used the FY97-98 audited and revised SOx emissions provided by the AQMD's RECLAIM Engineering & Compliance team on February 23, 2010 as the base. The AQMD's AER team refined and distributed the audited data by rule, by facility and by equipment types. The distributed 97-98 SOx baseline emissions with a total of 19.48 tons per day are then grown to 2019. Staff used composite growth factors from 2002 to 1997 and forecast growth factors from 2002 to 2019 of the 2007 AQMP to project SOx emissions in 2019. There were two existing SOx rules, R431.1 and R431.2, and seven new rules impacting the SOx universe. For this analysis, there should be no overlapping controls among rules. Therefore, overlapping controls from R431.1 & R431.2 are being overridden by the new rules. Sources not impacted by the new rules reflect controls from R431.1 & 431.2 when appropriate. The seven new rules with 2019 control factors impacting the SOx universe are:

Rule#	**Description**	**2019 Control Factor***
R468	Sulfur Recovery Units (SRUs)	0.63
R469	Sulfuric Acid Units	0.04
R1105.1	FCCU	0.06
R1109	Refineries Boilers & Heathers	0.20
R1117	Glass Melting Furnace	0.01
R1119	Coke Calciner	0.05
R1156	Portland Cement Mfg	0.74

*Draft Staff Report, page I-95 to I-99, Agenda#27 of 1/8/10 Board meeting.

The 2019 growth only emissions and the 2019 remaining SOx emissions are calculated to reflect controls from all rules. The 2019 SOx baseline with growth only, reductions and remaining emissions by rule are listed below:

Number	**Description**	**97-98 Audited Emissions**	**2019 Growth only Emissions**	**Reductions from Rules**	**2019 Remaining Emissions**
R468	Sulfur Recovery Units	2.03	2.03	0.75	1.28
R469	Sulfuric Acid Units	1.06	1.37	1.31	0.05
R1105.1	FCCU	5.68	5.68	5.34	0.34
R1109	Refineries Boilers & Heaters	6.11	6.11	4.88	1.22
R1117	Glass Melting Furnaces	1.71	2.48	2.45	0.02
R1119	Coke Calciner	1.31	1.31	1.25	0.07
R1156	Portland Cement Mfg	0.53	1.36	0.35	1.01
R431.1&2	Others	1.06	1.18	0.05	1.12
	Total (tons per day)	19.48	21.51	16.40	5.12

The above resulting table with more details is sent to the Rule Staff for further analysis.

Composite Growth Factors (2005-2019)

Rule Staff requested 2005-2019 composite growth factors for R469 (Sulfuric Acid Units), R1117 (Glass Melting Furnace) and R1156 (Cement Mfg.). Using growth factors in the 2007AQMP by county and by facility, the FY97-98 audited SOx values provided by the RECLAIM group are projected to 2005 and 2019. The projected emissions are then grouped by rule by facility. To calculate the composite growth factors from 2005 to 2019 by rule, staff divides sum of 2019 growth-only emissions by sum of 2005 growth-only emissions for each rule.

Appendix J – Socioeconomic Analysis

(Author: Shah Dabirian. The Socioeconomic Analysis is a stand-alone document attached by reference.)

- End of Document -